Southern Nuclear

Regulatory Affairs

3535 Colonnade Parkway
Birmingham, AL 35243

205 992 5000

May 15, 2025

Docket Nos.: 50-321
50-366

NL-25-0062

10 CFR 50
10 CFR 51
10 CFR 54

ATTN: Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Edwin I. Hatch Nuclear Plant, Units 1 and 2
HSLR-25-371, Application for Subsequent Renewal of Operating Licenses

Ladies and Gentlemen:
Pursuant to Title 10 of the Code of Federal Regulations, Part 50, “Domestic Licensing of Production and Utilization Facilities,” Part 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions,” and Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” Southern Nuclear Operating Company (SNC) is submitting this application for the renewal of the Edwin I. Hatch Nuclear Plant (HNP), Units 1 and 2, Renewed Facility Operating Licenses. The first Renewed Facility Operating Licenses for HNP Units 1 and 2, License Nos. DPR-57, and NPF-5, respectively, are set to expire at midnight on August 6, 2034, and June 13, 2038, respectively.

SNC seeks to extend the operating term of HNP Units 1 and 2 by 20 years beyond the current renewal license expiration dates.

The enclosed Subsequent License Renewal Application (SLRA) contains the information required by 10 CFR Parts 54 and 51 and meets the submittal timeliness requirements of 10 CFR 54.17(c) and 10 CFR 2.109(b). This submittal provides appropriate administrative, technical, and environmental information sufficient to support Nuclear Regulatory Commission (NRC) findings required by 10 CFR 54.29.

Enclosure 1 of this letter provides HNP SLRA Sections 1 through 4 and Appendices A through D. Enclosure 2 of this letter provides HNP SLRA Appendix E, Applicant’s Environmental Report–Operating License Renewal Stage.

As required by 10 CFR 54.21(b), current licensing basis changes which have a material effect on the content of this application will be submitted at least annually while the application is under NRC review and at least three months prior to the scheduled completion of the NRC review.

Appendix A, Table A-3, "List of SLR Implementation Actions and Implementation Schedule" of the enclosed HNP SLRA provides a list of implementation actions made in this application. This list will be updated as required throughout the SLRA review process.

This letter contains no NRC regulatory commitments. Should you have any questions regarding this submittal, please contact Amy Aughtman, Licensing and Environmental Manager, Subsequent License Renewal, at 205-992-7006 or agaughtm@southernco.com.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 15th day of May 2025.

Respectfully submitted,

Jamie Coleman

Jamie M. Coleman
Regulatory Affairs Director

JMC/dsp/cbg

Enclosures:

1. HNP Subsequent License Renewal Application Sections 1 through 4 and Appendices A through D

2. HNP Subsequent License Renewal Application Appendix E, Applicant's Environmental Report-Operating License Renewal Stage

Cc: NRC Regional Administrator, Region II
NRC Senior Resident Inspector – Hatch Nuclear Plant
Director, Office of Nuclear Reactor Regulation (NRR)
NRC Project Manager (Safety Review), NRR-DNRL
NRC Project Manager (Environmental Review), NMSS-REFS
NRC Project Manager, NRR-DORL – Hatch Nuclear Plant
Director, Environmental Protection Division - State of Georgia

RTYPE: CHA02.004

Edwin I. Hatch Nuclear Plant Unit 1 and 2
Application for Subsequent Renewal of Operating Licenses

Enclosure 1 to NL-25-0062

HNP Subsequent License Renewal Application
Sections 1 through 4 and Appendices A through D

EDWIN I. HATCH NUCLEAR PLANT

UNIT 1 AND UNIT 2

SUBSEQUENT LICENSE RENEWAL APPLICATION

MAY 2025

(1425 Total Pages, including cover sheets)

Edwin I. Hatch Nuclear Plant

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

MAY 2025

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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-57 and NPF-5) for Edwin I. Hatch Nuclear Plant (HNP) Unit 1 and Unit 2 (Reference 1.6.2 and 1.6.3). 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 1.6.11), Regulatory Guide (RG) 1.188, Revision 2, *Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses* (Reference 1.6.12), 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 1.6.13). 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 HNP.

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

Southern Nuclear Operating Company, Inc. (SNC) hereby applies for subsequent renewed operating license for HNP Unit 1 and Unit 2. SNC submits this application individually and as agent for the owner licensees named on the operating license. The owner licensees are as follows:

- Georgia Power Company
- Oglethorpe Power Corporation
- Municipal Electric Authority of Georgia
- Dalton Utilities

1.1.2 Address of Applicant

Southern Nuclear Operating Company, Inc.
3535 Colonnade Parkway,
Birmingham, AL 35243

Georgia Power Company
2100 Ralph McGill Blvd NE
Atlanta, GA 30308

Oglethorpe Power Corporation
2100 East Exchange Place
P.O. Box 1349
Tucker, Ga 30085-1349

Municipal Electric Authority of Georgia
1470 Riveredge Parkway, N.W.
Atlanta, Georgia 30328

Dalton Utilities
P.O. Box 869
Dalton, GA 30722

Address of the Edwin I. Hatch Nuclear Plant:
11028 Hatch Pkwy N
Baxley, Geogia 31513

1.1.3 Description of Business or Occupation of Applicant

Southern Nuclear Operating Company, Inc.

SNC is engaged in the operation of nuclear power plants. SNC operates HNP, Units 1 and 2 and the Vogtle Electric Generating Plant (VEGP), Units 1, 2, 3, and 4 for Georgia Power Company (GPC), Oglethorpe Power Corporation (OPC), the Municipal Electric

Authority of Georgia (MEAG), and Dalton Utilities (the owners); and the Joseph M. Farley Nuclear Plant (FNP), Units 1 and 2, for Alabama Power Company. The combined electric generation of the three sites is in excess of 8,300 MWe.

SNC is the exclusive licensed operator of the owners' nuclear facility, HNP, which is the subject of this application. The current Unit 1 license (Facility Operating License No. DPR-57) will expire at midnight on Aug 6, 2034, and the current Unit 2 license (Facility Operating License No. NPF-5) will expire at midnight on June 13, 2038. SNC will be named as the exclusive licensed operator on the renewed operating licenses.

Georgia Power Company

GPC is engaged in the generation and transmission of electricity and the distribution and sale of such electricity within the State of Georgia. GPC serves approximately 2.8 million customers in a service area of approximately 57,000 square miles constituting approximately 97 percent of the State of Georgia's land area. With a generating capacity of approximately 14,000 MW, GPC currently provides retail electric service in all but 4 of Georgia's 159 counties. GPC is an owner and licensee of HNP and will be named as an owner licensee on the renewed licenses.

Oglethorpe Power Corporation

OPC (an Electric Membership Corporation) supplies electricity at wholesale to 38 Electric Membership Corporations in the State of Georgia, which in turn distribute this electricity at retail to their residential, commercial and industrial customers. Oglethorpe is an owner and licensee of HNP and will be named as an owner licensee on the renewed licenses.

Municipal Electric Authority of Georgia

MEAG is an electric generation and transmission public organization, which provides wholesale power to 49 communities in the State of Georgia and other wholesale customers. These communities own and operate their local electric distribution systems and serve approximately 324,000 customer accounts. MEAG is an owner and licensee of HNP and will be named as an owner licensee on the renewed licenses.

Dalton Utilities

Dalton Utilities is a full-service municipal utility service supplying the City of Dalton within the state of Georgia. The City of Dalton Water, Light and Sinking Fund Commission oversees Dalton Utilities, which owns electric generation capacity, transmission capacity, and a distribution system. Dalton Utilities is an owner and licensee of HNP and will be named as an owner licensee on the renewed licenses.

1.1.4 Organization and Management of Applicant

Southern Nuclear Operating Company, Inc.

SNC is a Delaware corporation with its principal office in Birmingham, Alabama. It is a wholly-owned subsidiary of Southern Company, a company registered under the Public Utility Holding Company Act of 1935, having its principal place of business in Atlanta, Georgia. Other major subsidiaries of Southern Company include Alabama Power Company, Georgia Power Company, Mississippi Power Company, Southern Company Gas, Atlanta Gas Light, Chattanooga Gas Company, Nicor Gas Company, Virgina Natural Gas, Southern Power Company, PowerSecure, Southern Telecom, and Southern Linc.

Neither SNC nor its parent, Southern Company, is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. SNC files this application on its own behalf and as an agent of the owners.

The names and business addresses of SNC's directors and principal officers, all of whom are citizens of the United States, are as follows:

Southern Nuclear Operating Company, Inc. Directors and Principal Officers

Name	Title	Address
Directors		
Peter (Pete) P. Sena III	Chairman, President and CEO SNC	3535 Colonnade Pkwy Bham, AL 35243
Christopher C. Womack	Chairman, President and CEO Southern Company	30 Ivan Allen Jr. Blvd NW Atlanta, GA 30308
Stan W. Connally	EVP and COO, Southern Company	600 18th St N Bham, AL 35203
Kimberly S. Greene	Chairman, Pres and CEO GP	241 Ralph McGill Blvd Atlanta, GA 30308
Jeff Peoples	Chairman, Pres and CEO AP	600 18th St N Bham, AL 35203
Principal Officers		
Peter (Pete) P. Sena III	Chairman, President and CEO	3535 Colonnade Pkwy Bham, AL 35243
Richard Libra	EVP and Chief Nuclear Officer	3535 Colonnade Pkwy Bham, AL 35243
John Williams	SVP of Technical Services and External Affairs	3535 Colonnade Pkwy Bham, AL 35243
Earl Berry	VP Of Engineering	3535 Colonnade Pkwy Bham, AL 35243
Matthew Busch	Hatch VP	11028 Hatch Pkwy N Baxley, GA 31513
Shane Camp	VP of Human Resources	3535 Colonnade Pkwy Bham, AL 35243
Edwin (Sonny) D. Dean	Farley VP	7388 N County Rd 95 Columbia, AL 36319
Cheryl Gayheart	VP of Regulatory Affairs	3535 Colonnade Pkwy Bham, AL 35243
Patrick Martino	Vogtle Units 3&4 VP	7821 River Rd Waynesboro, GA 30830
Ho Nieh	VP, INPO Loaned Executive	3535 Colonnade Pkwy Bham, AL 35243

Southern Nuclear Operating Company, Inc. Directors and Principal Officers

Name	Title	Address
Steve Owen	VP, Project Controls Vogtle 3&4	7821 River Rd Waynesboro, GA 30830
Millicent W. Ronnlund	VP, General Counsel, & Compliance Officer	3535 Colonnade Pkwy Bham, AL 35243
Johnny Weissinger	Vogtle Units 1&2 VP	7821 River Rd Waynesboro, GA 30830
Aaron Abramovitz	Treasurer	241 Ralph McGill Blvd Atlanta, GA 30308
Chris Segroves	Comptroller	3535 Colonnade Pkwy Bham, AL 35243
Leslie Allen	Secretary	3535 Colonnade Pkwy Bham, AL 35243
Morgan Adams	Assistant Secretary	3535 Colonnade Pkwy Bham, AL 35243
Laura Hewett	Assistant Secretary	30 Ivan Allen Jr. Blvd NW Atlanta, GA 30308

The names and business addresses of Georgia Power's directors and principal officers, all of whom are citizens of the United States, are as follows:

Georgia Power Company Principal Officers

Name	Title	Address
Kim Greene	Chairman, President & CEO	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Aaron Abramovitz	Executive Vice President, CFO and Treasurer	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Trey Kilpatrick	Senior Vice President, External Affairs	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Latanza Adjei	Senior Vice President, Customer Experience	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Rick Anderson	Senior Vice President and Senior Production Officer	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Tami Barron	Senior Vice President, Distribution	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Fran Forehand	Senior Vice President, Transmission	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Lindsay Hill	Senior Vice President, Human Resources	2100 Ralph McGill Blvd NE Atlanta, GA 30308
David Slovensky	Senior Vice President, General Counsel and Corporate Secretary	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Jason Cuevas	Vice President, Corporate Responsibility President and CEO, Georgia Power Foundation	2100 Ralph McGill Blvd NE Atlanta, GA 30308

Georgia Power Company Board of Directors

Name	Address
Kim Greene	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Mark Burns	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Jill Bullock	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Drew Evans	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Steven Ewing	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Tommy Holder	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Kessel Stelling	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Charles Tarbutton	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Clyde Tuggle	2100 Ralph McGill Blvd NE Atlanta, GA 30308
T. Dallas Smith	2100 Ralph McGill Blvd NE Atlanta, GA 30308
Virgil R. Miller	2100 Ralph McGill Blvd NE Atlanta, GA 30308

The names and business addresses of MEAG's directors and principal officers, all of whom are citizens of the United States, are as follows:

Municipal Electric Authority of Georgia Principal Officers

Name	Title	Address
James E. Fuller	President and Chief Executive Officer	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Peter M. Degnan	Senior Vice President and General Counsel	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Steven M. Jackson	Senior Vice President and COO	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Reiko A. Kerr	Senior Vice President, Finance & Administration, and CFO	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Douglas K. Lego	Senior Vice President, Transmission	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Paul J. Warfel	VP of Participant and External Affairs	1470 Riveredge Parkway, N.W Atlanta, GA 30328

Municipal Electric Authority of Georgia Board of Directors

Name	Title	Address
Larry M. Vickery	Chairman	1470 Riveredge Parkway, N.W Atlanta, GA 30328
L. Timothy Houston, Sr.	Vice Chairman	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Patrick C. Bowie, Jr.	Secretary-Treasurer	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Terrell D. Jacobs	City Manager, Albany	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Gregory P. Thompson	Businessman, Monroe	1470 Riveredge Parkway, N.W Atlanta, GA 30328
R. Steve Tumlin, Jr.	Mayor, Marietta	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Chad E. Warbington	Mayor Pro Tem, Albany	1470 Riveredge Parkway, N.W Atlanta, GA 30328
Eric S. Wilson	Mayor, Forsyth	1470 Riveredge Parkway, N.W Atlanta, GA 30328
William J. Yearta	State Representative, Sylvester	1470 Riveredge Parkway, N.W Atlanta, GA 30328

The names and business addresses of Oglethorpe Power's directors and principal officers, all of whom are citizens of the United States, are as follows:

Oglethorpe Power Corporation Principal Officers

Name	Title	Address
Annalisa M. Bloodworth	President and Chief Executive Officer	2100 East Exchange Place Tucker, GA 30085
Betsy B. Higgins	Executive Vice President and Chief Financial Officer	2100 East Exchange Place Tucker, GA 30085
Rich Wallen	Executive Vice President and Chief Operating Officer	2100 East Exchange Place Tucker, GA 30085
Billy F. Ussery	Executive Vice President, Member Relations	2100 East Exchange Place Tucker, GA 30085
Suzanne N. Roberts	Senior Vice President and General Counsel	2100 East Exchange Place Tucker, GA 30085
Jeffrey R. Swartz	Senior Vice President, Plant Operations	2100 East Exchange Place Tucker, GA 30085
Heather H. Teilhet	Executive Vice President, External Affairs	2100 East Exchange Place Tucker, GA 30085
Jami G. Reusch	Senior Vice President, Human Resources	2100 East Exchange Place Tucker, GA 30085

Oglethorpe Power Corporation Board of Directors

Name	Title	Address
Marshall S. Millwood	Chairman of the Board	7745 Waldrip Road Gainesville, GA 30506
James I. White	Vice Chairman of the Board	167 White Drive Stockbridge, GA 30281
Jimmy G. Bailey	Member At-Large Director	252 Grayson Trail Hogansville, GA 30230
Horace H. Weathersby III	Member At-Large Director	5654 Hooks Road Millen, GA 30442
Sam Simonthon	Service Management Group No.2 Member Director	900 Loth Wages Road Dacula, GA 30019
Fred A. McWhorter	Service Management Group No.4 Member Director	1911 White Rock Road Lincolnton, GA 30817
George L. Weaver	Service Management Group No.1 Manager Director	Central Georgia EMC 923 S. Mulberry Street Jackson, GA 30233
Danny Nichols	Service Management Group No.2 Manager Director	Colquitt EMC P.O. Box 3608 Moultrie, GA 31776
Randy Crenshaw	Service Management Group No.3 Manager Director	Irwin EMC P.O. Box 125 Ocilla, GA 31774
Jeffrey W. Murphy	Service Management Group No.4 Manager Director	Hart EMC P.O. Box 250 Hartwell, GA 30643
Earnest A. (Chip) Jakins, III	Service Management Group No.5 Manager Director	Jackson EMC P.O. Box 38 Jefferson, GA 30549
W. Ronald Duffey	Outside Director	6 Dogwood Road Newnan, GA 30263

The names and business addresses of The City of Dalton's city officials, board of commissioners, and Dalton Utilities CEO, all of whom are citizens of the United States, are as follows:

City of Dalton Officials, Board of Commissioners, and Dalton Utilities CEO

Name	Title	Address
City Officials		
Annalee Sams	Mayor	300 W Waugh St Dalton, GA 30720
Andrew Parker	City Administrator	300 W Waugh St Dalton, GA 30720
Bernadette Chattam	City Clerk	300 W Waugh St Dalton, GA 30720
City Board of Commissioners		
Joe Yarbrough	Chairman	P.O. Box 869 Dalton, GA 30722
Ed Anthony	Vice-Chair	P.O. Box 869 Dalton, GA 30722
Kevin Brunson	Secretary	P.O. Box 869 Dalton, GA 30722
Tommy Boggs	Board Member	P.O. Box 869 Dalton, GA 30722
Tommy Thompson	Board Member	P.O. Box 869 Dalton, GA 30722
Dalton Utilities		
John Thomas	CEO, Dalton Utilities	P.O. Box 869 Dalton, GA 30722

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

SNC is requesting subsequent renewal of a Class 104 operating license for HNP Unit 1 and a Class 103 operating license for Unit 2 (License Nos. DPR-57 and NPF-5, respectively) for an additional 20 years of operation beyond the expiration of the current licenses, midnight, August 6, 2034 for Unit 1 and midnight, June 13, 2038 for Unit 2.

Additionally, 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.

1.1.6 Earliest and Latest Dates for Alterations

SNC 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 Restricted Data

With regard to the requirements of 10 CFR 54.17(f), this application does not contain any "Restricted Data," as that term is defined in the Atomic Energy Act of 1954, as amended, or other defense information, and it is not expected that any such information will become involved in these licensed activities.

In accordance with the requirements of 10 CFR 54.17(g), the applicants will not permit any individual to have access to, or any facility to possess restricted data or classified national security information until the individual and/or facility has been approved for such access under the provisions of 10 CFR Parts 25 (Reference 1.6.7) and/or 95 (Reference 1.6.9).

1.1.8 Listing of Regulatory Agencies having Jurisdiction

The direct costs incurred by SNC in connection with HNP are billed directly to GPC. Expenses which are not direct charges to specific plants are allocated to GPC and others for whom the expenses are incurred, as appropriate. GPC recovers a portion of HNP direct and allocated costs from the other owners in relation to their respective ownership interests in HNP, and the remainder through rates. The rates charged and services provided by GPC are subject to the jurisdiction of the Georgia Public Service Commission and the Federal Energy Regulatory Commission.

Georgia Public Service Commission
244 Washington St. S.W.
Atlanta, Georgia 30334

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

1.1.9 Appropriate News Publications

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

The Baxley News-Banner
P.O. Box 410
Baxley, Georgia 31515
912-367-2468
Fax-912-367-0277

The Advance
205 E. First St
Vidalia, GA 30475
912-537-3131
Fax-912-537-4899

The Tattnall Journal
114 N Main St.
Reidsville, GA 30453
912-557-6761
Email: mail@tattnalljournal.com

The Jeff Davis Ledger
12 Latimer St.
Hazlehurst, GA 31539
912-375-4225
Email: news@jdledger.com

The Macon Telegraph
1675 Montpelier Avenue
Macon, GA 31201
478-744-4200

Savannah Morning News
1-888-348-3309

1.1.10 Conforming Changes to Standard Indemnity Agreement

10 CFR 54.19(b) requires that "each application must include conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." The current indemnity agreement (No. B-69) for HNP states, in Article VII, that the agreement "shall terminate at the time of expiration of that license specified in Item 3 of the Attachment, which is the last to expire." As a result of Amendments 2 and 9, Item 3 of the Attachment to the indemnity agreement lists license number DPR-57 (for HNP Unit 1) and NPF-5 (for HNP Unit 2). SNC requests that any necessary conforming changes be made to Article VII and Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate to ensure that the indemnity agreement continues to apply during both the terms of the current licenses and the terms of the renewed licenses. SNC understands that no changes may be necessary for this purpose if the current license numbers for HNP Units 1 and 2 are retained.

1.2 PLANT DESCRIPTION

HNP is a two-unit boiling water reactor (BWR) located on the south side of the Altamaha River in Appling County, Georgia, approximately 11 miles north of Baxley, Georgia. The reactor buildings and turbine buildings are separate for each unit. The control building is a shared facility between the two turbine buildings. The turbine buildings and control building are connected in such a manner as to provide a common turbine hall. Similarly, the refueling floors of both reactor buildings are joined together into a single area. The nuclear steam supply systems (NSSS) for both units include BWR 4, 1967 product line, 218-in. vessels, designed and supplied by GE. The containments are of the Mark I design, incorporating a drywell and torus to provide pressure suppression.

At the time of the first License Renewal, the design operating power was 2763 MWt for each unit. Following issuance of the renewed licenses, in September 2003 the NRC issued Amendment 238 to Renewed Facility Operating License DPR-57 and Amendment 180 to Renewed Facility Operating License NPF-5 that increased the operating power level to 2804 MWt for both units (Reference 1.6.8).

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 1.6.10). 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.

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 AMR 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 made available to the NRC.

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(c)(1)(i) (iii). Section 4 also confirms that there are no 10 CFR 50.12 exemptions involving TLAAs as defined in 10 CFR 54.3 identified for the SPEO.

Appendix A – Final Safety Analysis Report Supplement

As required by 10 CFR 54.21(d), the Final Safety Analysis Report (FSAR) supplement contains a summary of programs and activities credited for aging management during the renewal term. Also contained in Appendix A is a list of the TLAAs and their dispositions. The SLR implementation actions 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 FSAR.

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 provides the requested responses to applicant action items contained in the NRC Safety Evaluation Reports associated with NRC approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) reports.

Appendix D – Technical Specification Changes

This appendix satisfies the requirement in 10 CFR 54.22 to identify technical specification changes or additions necessary to manage the effects of aging during the SPEO. There are no technical specification changes identified as necessary to manage the effects of aging during the SPEO.

Appendix E – Applicant's Environmental Report

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 HNP.

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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), HNP will maintain (1) a summary description of programs and activities in the FSAR for managing the effects of aging, (2) summaries of the TLAA evaluations, and (3) descriptions of the in-scope implementation actions for the SPEO.

1.5 CONTACT INFORMATION

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1.6 GENERAL REFERENCES

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

1.6.2 DPR-57, *Renewed Facility Operating License for Hatch Nuclear Plant Unit 1*, January 15, 2002, ADAMS Accession No. ML052930172.

1.6.3 NPF-5, *Renewed Facility Operating License for Hatch Nuclear Plant Unit 2*, January 15, 2002, ADAMS Accession No. ML052930177.

1.6.4 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 Criteria (Non-Safety Affecting Safety)*, June 2005.

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 50, *Domestic Licensing of Production and Utilization Facilities*.

1.6.7 10 CFR 25, *Access Authorization*.

1.6.8 Edwin I Hatch Nuclear Plant, Units 1 and 2-Issuance of Amendments Regarding Appendix K Measurement Uncertainty Recovery (TAC Nos. MB7026 and MB7027), September 23, 2003, ADAMS Accession No. ML032590944.

1.6.9 10 CFR 95, *Facility Security Clearance and Safeguarding of National Security Information and Restricted Data.*

1.6.10 NUREG-2191, Revision 1 Draft Report, *Generic Aging Lessons Learned for Subsequent License Renewal (GALL SLR) Report*, Volumes 1 and 2, United States Nuclear Regulatory Commission, July 2023, ADAMS Accession Nos. ML23180A182 and ML23180A188.

1.6.11 NUREG-2192, Revision 1 Draft Report, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants*, United States Nuclear Regulatory Commission, July 2023, ADAMS Accession No. ML23180A191.

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

1.6.13 10 CFR 51, *Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions*.

1.6.14 Edwin I. Hatch Nuclear Plant Application for Renewed Operating Licenses, February 29, 2000, ADAMS Accession No. ML03688151.

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

1.6.16 NUREG-1803, *Safety Evaluation Report Related to the License Renewal of the Edwin I. Hatch Nuclear Plants, Units 1 and 2*, ADAMS Accension Nos. ML020020160, ML020020291 and ML020020301.

1.6.17 BWRVIP-190, Revision 2, *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*.

1.6.18 NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*. ADAMS Accension No. ML031430208.

1.6.19 EPRI Report 3002015824, *Nuclear Maintenance Applications Center: Bolted Joint Fundamentals*, Revision 1.

1.6.20 EPRI Report 3002008061, *Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Joints: Update of Report 1015337*.

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

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

1.6.23 RG 1.163, *Performance-Based Containment Leak-Test Program*, Revision 1, June, 2023.

1.6.24 NEI 94-01, *Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J*, Revision 3A, July 2012.

1.6.25 ANSI/ANS-56.8-2002, *Containment System Leakage Testing Requirements*, November 2002.

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

1.6.27 NUMARC 93-01, *Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, April 2011.

1.6.28 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.

1.6.29 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.

1.6.30 ASTM D4537-04, *Standard Guide for Establishing Procedures to Qualify and Certify Personnel Performing Coating and Lining Work Inspection in Nuclear Facilities*.

1.6.31 ASTM D5498-12, *Standard Guide for Developing a Training Program for Personnel Performing Coating and Lining Work Inspection for Nuclear Facilities*.

1.6.32 EPRI Report 1006756, *Fire Protection Equipment Surveillance Optimization and Maintenance Guide.*

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
AERM	Aging Effect Requiring Management
AMP	Aging Management Program
AMR	Aging Management Review
ANSI	American National Standards Institute
API	American Petroleum Institute
ARI	Alternate Rod Injection
ART	Adjusted Reference Temperature
ASME	American Society of Mechanical Engineers
ASR	Alkali-Silica Reaction
AST	Alternate Source Term
ASTM	American Society for Testing and Materials
ATTS	Analog Transmitter Trip System
ATWS	Anticipated Transient Without Scram
BTP	Branch Technical Position
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
BWRVIP	Boiling Water Reactor Vessel Internals Project
CAC	Containment Atmosphere Cooling
CAD	Containment Atmospheric Dilution
CAP	Corrective Action Program
CASS	Cast Austenitic Stainless Steel

Table 1.7-1
Acronyms

Acronym	Description
CBCW	Control Building Chilled Water
CCCW	Closed-Cycle Cooling Water
CDT	Compressed Desirable Threshold
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CMU	Concrete Masonry Unit
CO_2	Carbon dioxide
CR	Condition Report
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
CS	Core Spray
CST	Condensate Storage Tank
CUF	Cumulative Usage Factor
CUF_{en}	Cumulative Usage Factor (Environmental-Assisted Fatigue)
DBA	Design Basis Accident
DBD	Design Basis Document
DBE	Design Basis Event
DC	Direct Current
DG	Diesel Generator
DMW	Dissimilar Metal Weld
DO	Dissolved Oxygen
DOE	Department of Energy
DOR	Division of Operating Reactors
dP	Differential Pressure
EAF	Environmentally Assisted Fatigue
ECCS	Emergency Core Cooling System
ECT	Eddy Current Testing

Table 1.7-1
Acronyms

Acronym	Description
EDG	Emergency Diesel Generator
EDGJW	Emergency Diesel Generator Jacket Water
EFPY	Effective Full Power Years
EHC	Electro-Hydraulic Control
EMA	Equivalent Margin Analysis
EOC	End of Cycle
EOL	End of Life
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EPU	Extended Power Uprate
EQ	Environmental Qualification
EQML	Environmental Qualification Master List
EQRE	Environmental Qualification Report Evaluation
ERFBS	Electrical Raceway Fire Barrier System
ESE	Erosion Susceptibility Evaluation
ESF	Engineered Safety Features
EVT	Enhanced Visual Examination
FAC	Flow-Accelerated Corrosion
F_{en}	Environmental Fatigue
FHA	Fire Hazards Analysis
FOST	Fuel Oil Storage Tank
FP	Fire Protection
FPCC	Fuel Pool Cooling and Cleanup System
FSAR	Final Safety Analysis Report
GALL	Generic Aging Lessons Learned
GDC	General Design Criterion

Table 1.7-1
Acronyms

Acronym	Description
GL	Generic Letter
GSI	Generic Safety Issue
HAZ	Heat Affected Zone
HCF	High Cycle Fatigue
HELB	High Energy Line Break
HNP	Hatch Nuclear Plant
HPCI	High Pressure Coolant Injection System
HVAC	Heating, Ventilation and Air Conditioning
HWC	Hydrogen Water Chemistry
HX	Heat Exchanger
I&C	Instrumentation & Controls
IASCC	Irradiation Assisted Stress Corrosion Cracking
ICMH	Incore-Monitoring Housing
ID	Inside Diameter
IE	Irradiation Embrittlement
IEB	Inspection and Enforcement Bulletin
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	Intergranular Stress Corrosion Cracking
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IPA	Integrated Plant Assessment
IR	Insulation Resistance
IRM	Intermediate Range Monitor
ISI	In-Service Inspection
ISP	Integrated Surveillance Program
IWB	Requirements for Class 1 Components of Light-Water Cooled Power Plants

Table 1.7-1
Acronyms

Acronym	Description
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
kV	1000 Volts or 1 kilo-Volt
LAR	License Amendment Request
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
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
MeV	Mega Electron Volt
MG	Motor Generator
MIC	Microbiologically Influenced Corrosion
MoS_2	Molybdenum Disulfide
MS	Main Steam
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
MSLB	Main Steam Line Break
NACE	National Association of Corrosion Engineers

Table 1.7-1
Acronyms

Acronym	Description
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NESC	National Electric Safety Code
NFPA	National Fire Protection Association
N_2	Nitrogen
Ni	Nickel
NP	Nuclear Procedure
NPS	Nominal Pipe Size
NRC	Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSR	Nonsafety-Related
NSSS	Nuclear Steam Supply System
NUMARC	Nuclear Utility Management and Resource Council
NUREG	U.S. Nuclear Regulatory Commission technical report designation
O_2	Oxygen
OAR	Owner’s Activity Report
OE	Operating Experience
P&ID	Piping and Instrument Diagram
PCCW	Primary Containment Chilled Water
PEO	Period of Extended Operation
PFM	Probabilistic Fracture Mechanics
pH	Concentration of Hydrogen Ions
PM	Preventive Maintenance
PRM	Process Radiation Monitor
PSW	Plant Service Water
P-T	Pressure Temperature
PTLR	Pressure and Temperature Limits Report

Table 1.7-1
Acronyms

Acronym	Description
PTS	Pressurized Thermal Shock
PWR	Pressurized Water Reactor
QA	Quality Assurance
QATR	Quality Assurance Topical Report
RAI	Request for Additional Information
RAMA	Radiation Analysis Modeling Application
RBCCW	Reactor Building Closed Cooling Water
RBRWCW	Reactor Building and Radwaste Building Chilled Water
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RG	Regulatory Guide (NRC)
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RIS	Regulatory Issue Summary
RPS	Reactor Protection System
RPT	Recirculation Pump Trip
RPV	Reactor Pressure Vessel
RT	Radiographic Testing
RT_{NDT}	Reference Temperature for Nil Ductility Transition
RVI	Reactor Vessel Internals
RWB	Radioactive Waste Building
RWCU	Reactor Water Cleanup
SBGT	Standby Gas Treatment
SBLC	Standby Liquid Control
SBO	Station Blackout

Table 1.7-1
Acronyms

Acronym	Description
SCFM	Standard Cubic Feet per Minute
SC	Structure or Component
SCC	Stress Corrosion Cracking
SED	System Evaluation Document
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SHB	Shroud Head Bolt
SLC	Standby Liquid Control
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SMP	Structural Monitoring Program
SNC	Southern Nuclear Operating Company
SO_2	Sulfur dioxide
SOER	Significant Operating Experience Report
SPEO	Subsequent Period of Extended of Operation
SR	Safety-Related
SRP	Standard Review Plan
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
TDR	Time Domain Reflectometry
TLAA	Time-Limited Aging Analysis
TPO	Thermal Power Optimization
TR	Technical Report

Table 1.7-1
Acronyms

Acronym	Description
TWC	Torus Water Cleanup
UPS	Uninterruptible Power Supply
USE	Upper Shelf Energy
UT	Ultrasonic Testing
UV	Ultraviolet
VAC	Volts-Alternating Current
VDC	Volts-Direct Current
VFLD	Vessel Flange Leak Detection
VT	Visual Examination
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 aging management review (AMR) in the Hatch Nuclear Plant (HNP) Integrated Plant Assessment (IPA). For the systems, structures, and components (SSCs) within the scope of subsequent license renewal (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 scoping and screening process is provided in Section 2.1.

The scoping and screening methodology is implemented in accordance with NEI 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal* (Reference 1.6.5). 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 the HNP Units 1 and 2 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 HNP LR project is described in the HNP original LRA. The technical documentation developed in support of that application is 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, 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, 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. 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, are scoped and screened as commodities. The structural commodities are evaluated for each in-scope structure and structural component group while electrical commodities are 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 TRs. The TRs contain evaluations and bases for decisions or positions associated with SLR requirements as described below. TRs 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 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. The CLBs for HNP Units 1 and 2 have been defined in accordance with the definition provided in 10 CFR 54.3. The key information sources that form the CLBs for HNP Units 1 and 2 include the FSARs, Technical Specifications, and the docketed licensing correspondence. Other important information sources used for scoping are further described in 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 HNP, 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 SLR systems and structures is based on the guidance provided in NEI 17-01 and NUREG-2191. The list of systems and structures evaluated in the scoping technical report are provided in Table 2.2-1.

Certain structures and equipment were excluded at the outset because they are not considered to be SSCs that are part of the CLB for HNP Units 1 and 2 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
- Engineered Safety Features (ESF)
- Auxiliary Systems
- Steam and Power Conversion 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 criteria. 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.*

No SR components have been excluded from the scope of SLR.

In 2008, the NRC issued license amendments supported by a Safety Evaluation Report (SER) accepting the HNP Unit 1 and 2 implementation of alternative source term (AST) methodology; therefore, the requirements of 10 CFR 50.67 are applicable to HNP.

Safety classifications of SSCs are included in the controlled component database and were established based on reliance on the SSCs during and following design basis events (DBEs), which include design basis accidents (DBAs), anticipated operational occurrences, natural phenomena, and external events. The DBEs considered for the HNP Units 1 and 2 CLBs are consistent with 10 CFR 50.49(b)(1).

Natural phenomena and external events are described in Chapter 12 of the HNP Unit 1 FSAR and Chapter 3 of the Unit 2 FSAR. Structures designed to withstand DBEs, natural phenomena, and external events are also described in Chapter 12 of the HNP Unit 1 FSAR and Chapter 3 of the HNP Unit 2 FSAR. Chapter 15.3 of the HNP Unit 2 FSAR, which is applicable to both units, provides the DBA analyses for each unit.

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

- The FSARs, Technical Specifications, TRMs, System Evaluation Document (SED), Maintenance Rule Scoping Manual, controlled component database, 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.

The scoping process to identify SR systems and structures 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 1.6.4), Appendix F, for industry guidance related to 10 CFR 54.4(a)(2) scoping criteria.

Consistent with this guidance, the NSR SSCs that are within the scope of SLR fall into three categories:

- NSR SSCs that may have the potential to prevent satisfactory accomplishment of safety functions,
- NSR SSCs directly connected to SR SSCs that provide structural support for the SR SSCs, 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 HNP Units 1 and 2 CLBs. These NSR SSCs are identified by reviewing the HNP Units 1 and 2 FSARs, SED, Maintenance Rule Scoping Manual, and other CLB documents. In addition, a supporting system review was performed to identify any NSR systems that support a SR intended function of a system included within the scope of SLR in accordance with 10 CFR 54.4(a)(1). 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 HNP Units 1 and 2 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:

- 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 HNP Units 1 and 2 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 commitments made to the National Fire Protection Associate (NFPA) Standard 805.

Systems and structures in the scope of SLR for FP include those required for compliance with 10 CFR 50.48(a) and 10 CFR 50.48(c). Equipment relied on for FP includes SSCs credited with fire prevention, detection, and mitigation in areas containing equipment important to safe operation of the plant, as well as systems that contain plant components credited to maintain the nuclear fuel in a safe and stable condition. The definition of a “Safe and Stable” condition is consistent with the nuclear safety performance criteria documented in NFPA 805, Section 1.5.1. The nuclear safety capability assessment (NSCA) is the term used by NFPA 805 to represent the safe shutdown analysis (SSA) within the context of NFPA 805.

The HNP Unit 1 and 2 Safe Shutdown Equipment List is included in the NFPA 805 NSCA and provides the list of equipment necessary to bring the plant to a “Safe and

Stable" condition as determined by the fire SSA. The NSCA Safe Shutdown Equipment List also contains power generation and distribution equipment that are required for the safe operation of the listed components

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

- The FSARs, Technical Specifications, TRMs, NSCA Safe Shutdown Equipment List, licensing correspondence, FP Program, Design Basis Document (DBD), 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.

The scoping process to identify systems and structures relied upon and/or specifically committed for FP 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 equipment that is in the EQ Program is discussed in Unit 1 FSAR Section 7.16.2 and Unit 2 FSAR Section 3.11.1 and is listed in the HNP Unit 1 and 2 EQ Master List (EQML). The EQML provides a comprehensive list of the equipment required to meet the requirements of 10 CFR 50.49.

Based on the EQML, LR intended functions relative to the criterion of 10 CFR 54.4(a)(3) for EQ were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed for EQ for HNP Units 1 and 2 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 boiling water reactors (BWRs) such as HNP.

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 (RPS) 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 is the following:

(a) An alternate rod insertion (ARI) system, diverse from the RPS, to vent the scram air header automatically under ATWS conditions.
(b) A recirculation pump trip (RPT) system to trip the reactor recirculation pumps automatically under ATWS conditions.
(c) A standby liquid control (SBLC) 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.

The HNP design features related to ATWS events are described in detail in Unit 1 FSAR section 7.2.3 and Unit 2 FSAR sections 7.6.10.7, 15.4.5, and 15C.4.3.5.

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

- The FSARs, Technical Specifications, TRMs, licensing correspondence, and design drawings were reviewed, as applicable.
- Based on the above, SLR intended functions relative to the criterion of 10 CFR 54.4(a)(3) for ATWS events were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed for ATWS 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 SSCs 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 (AAC) sources, nor does it assume a concurrent single failure or DBA.

At HNP, the SBO Rule is implemented by methods described in Nuclear Utility Management and Resource Council (NUMARC) 87-00 and RG 1.155. For both Units 1 and 2, the Unit 2 FSAR Section 8.4 summarizes how the plant can successfully withstand and recover from the SBO event.

HNP is an AAC plant. The design basis SBO event is a four-hour event. For both units, any one of the three emergency diesel generators (EDGs) can be used as an AAC source for SBO coping. However, EDG 1B is designated as the AAC power source for either unit and can be aligned to Division 1 load centers and initiated within 1 hour to the blacked out unit when diesel loading margins are met. Plant coping is controlled predominately by Class 1E direct current (DC) power and steam driven sources until the AAC power is available for loading. A combination of battery power and emergency ac power from the AAC source is used to bring the blacked-out unit to and maintain a hot shutdown condition from full power. After 4 hours, either offsite power is restored or the additional EDG is started to bring the plant to a cold shutdown condition.

NUREG-2192, Section 2.5.2.1.1 Components Within the Scope of SBO (10 CFR 50.63) specifies that the plant portion of the offsite power system that is used to connect the plant to the offsite power source meets the requirements of 10 CFR 54.4(a)(3). The SBO scoping for HNP includes the recovery path electrical equipment out to the first circuit breaker connecting to the offsite transmission system (i.e., equipment in the switchyard) consistent with the NUREG-2192 guidance. This path includes the circuit breakers that connect the switchyard to the transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between the circuit breakers and transformers, the transformers and onsite electrical distribution system and the associated control circuits and structures. The SBO scoping and recovery paths are further described in the electrical commodity screening and AMR report.

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

- The FSARs, Technical Specifications, TRMs, licensing correspondence, 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 SBO were identified for each system and structure determined to meet this criterion.

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

2.1.3 Information Sources Used for Scoping and Screening

In addition to the HNP Unit 1 and Unit 2 FSARs, Technical Specifications, and TRMs, the following additional CLB and other information sources were relied upon to a great extent in performing scoping and screening for HNP Units 1 and 2. Information used in this SLRA is current as of September 30, 2024. A brief discussion of these sources is provided.

2.1.3.1 Controlled Plant Component Database

Specific component information for SSCs can be found in the controlled component database. The controlled 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.

2.1.3.2 Plant Drawings

HNP drawings were used as references when performing SSC evaluations for SLR. 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.

For mechanical systems, all applicable P&IDs were reviewed to identify the specific system boundaries included in the scope of SLR.

2.1.3.3 Fire Protection Program

The HNP safe shutdown equipment list located in the NFPA 805 NSCA is used to determine equipment required to reach safe and stable conditions following a fire. Design drawings are also used to determine which fire suppression components are located in areas that contain safe shutdown equipment.

2.1.3.4 Station Blackout Equipment

Equipment relied upon to mitigate an SBO event at HNP Unit 1 and 2 is described in Section 8.4 of the Unit 2 FSAR. This FSAR section (and references therein) was used to identify components and equipment credited for SBO that are not classified as SR and/or not already included within the scope of SLR. 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.

2.1.3.5 Environmental Qualification Documentation

The HNP Unit 1 and 2 EQML provides a detailed listing of all equipment and components that must be environmentally qualified for use in a harsh environment. This HNP EQML is used to identify equipment that must meet specific EQs.

2.1.3.6 Original License Renewal Documents

Documentation from the initial LRA was used to inform the identification of systems and structures within the scope of SLR. This documentation includes the original LRA scoping, screening, and AMR reports. Although the original LRA reports were reviewed and approved and are considered QA records, they are not used as design input for SLR scoping because the LRA reports have not been maintained current beyond any updates required by 10 CFR 54.37(b). The following documents were used when preparing this SLRA:

- Application for Renewed Operating Licenses, Plant Hatch Units 1 and 2 and related docketed regulatory correspondence.
- NUREG-1803, Safety Evaluation Report Related to the License Renewal of the Edwin I. Hatch Nuclear Plants, Units 1 and 2 (Reference 1.6.16).

2.1.3.7 Other Current Licensing Basis References

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

- NRC SERs including NRC staff review of HNP major licensing submittals, such as power uprates, NFPA 805, license amendment requests (LARs), etc..
- 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 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 documents. The system and structure scoping results are provided in Table 2.2-1.

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

Each 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)
  - 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 SLR 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.*

The SR components are identified in the safety component list in the SED. The SR classification in the safety component list was determined by a functional analysis of the entire system as well as the individual components within the system. The SR classification of each system and component is also listed in the controlled component database, and this information is used to confirm or adjust the system classification as necessary.

SR classifications for systems and structures are based on system and structure descriptions and analysis in the FSARs. SR structures are those structures listed in the FSARs and classified as Class I. Systems and structures identified as SR in the FSARs meet the criteria of 10 CFR 54.4(a)(1) and are included within the scope of SLR. SR components in the safety component list from the SED and the controlled component 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 HNP Units 1 and 2 CLBs, 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 that provide structural support for the SR SSCs, 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.

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 HNP Units 1 and 2 CLBs where this can occur include the following:

Cranes/Overhead Handling Systems: Cranes are used in support of unit operations and maintenance activities and may be used to move heavy loads over SR equipment, spent fuel, or fuel in the core. The overhead-handling systems, from which a load drop could result in damage to any system that could prevent the accomplishment of a SR function, are considered to meet the criteria of 10 CFR 54.4(a)(2) and within the scope of SLR.

High-Energy Line Break (HELB): For HNP, the definition of high energy piping systems are fluid systems which exceed 200°F or 275 psig during normal operating conditions. HNP also defines moderate energy piping systems for non–flashing (i.e., fluid systems which are 200°F or less, and 275 psig or greater) and flashing (i.e., fluid systems which are greater than 200°F, and less than 275 psig). High energy or moderate energy piping 1” nominal pipe size and smaller are excluded from HELB review by the HNP CLB.

HELBs outside of containment were evaluated as documented in Supplements 15A and 15A.A of the HNP Unit 2 FSAR (applicable to both units). These same descriptions for high energy and moderate energy 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. In addition, the pipe whip restraints, jet impingement shields, seismic supports, and other structural protective/mitigative features for high-energy and moderate-energy line breaks were included in the scope and evaluated.

NSR whip restraints, jet impingement shields, blowout panels, etc. that are designed and installed to protect SR equipment from the effects of a HELB are within the scope of SLR per 10 CFR 54.4(a)(2).

Internal and External Missile Hazards: Missiles can be generated from internal events such as failure of rotating equipment or external events. Inherent NSR features that protect SR equipment from internal and external missiles are within the scope of SLR per 10 CFR 54.4(a)(2).

Internal and External Flooding Events: Flooding from various sources is generally considered during design of the plant. Typically, only equipment in the lowest levels of the plant are susceptible to flooding. This assumes open stairwells and floor grating to allow floodwater to cascade to lower levels. If a room does not allow for cascading, it is dispositioned on a plant-specific basis. If level instrumentation and alarms are utilized to warn the operators of flood conditions, and operator action is necessary to mitigate the flood, then these instruments and alarms are within the scope of SLR per 10 CFR 54.4(a)(2). NSR sump pumps, piping and valves that are necessary to mitigate the effects of a flood that threatens SR intended functions of SSCs are also within the scope of SLR per 10 CFR 54.4(a)(2). Walls, curbs, dikes, doors, etc. that provide flood barriers to SR SSCs are within the scope of SLR per 10 CFR 54.4(a)(2) and are typically included as part of the building structure.

NSR SSCs Required to Functionally Support SR SSCs: In some cases, SR SSCs may rely on certain NSR SSCs to perform a system intended function. These NSR SSCs are identified within the individual systems.

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 SR/NSR interface, are within the scope of SLR per 10 CFR 54.4(a)(2).

For this purpose, the "first seismic or equivalent anchor" must be defined such that the failure in the NSR pipe run beyond the first seismic or equivalent anchor will not render the SR portion of the piping unable to perform its intended function under CLB design conditions.

The following criteria from Appendix F of NEI 95-10, Rev. 6 apply to the identification of the first seismic or equivalent anchor:

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

An alternative to specifically identifying a seismic anchor or series of equivalent anchors that support the SR/NSR piping interface is to include enough of the NSR piping run to ensure that these anchors are included and thereby ensure the piping and anchor intended functions are maintained. The intended function of the first seismic or equivalent anchor consists of two facets:

(1) Providing structural support for the SR/NSR interface, and
(2) Ensuring NSR piping loads are not transferred through the SR/NSR interface.

The following methods (a) through (d) were used to define end points for the portion of NSR piping attached to SR piping to be included in the scope of SLR. The bounding criteria in methods (a) through (d) provide assurance that SLR scoping encompasses the NSR piping systems included in the design basis seismic analysis and is consistent with the CLB.

(a) A base-mounted component that is a rugged component and is designed not to impose loads on connecting piping. The SLR scope includes the base-mounted component as it has a support function for the SR piping.
(b) A flexible connection is considered a pipe stress analysis model end point when the flexible connection effectively decouples the piping system.
(c) A free end of NSR piping, such as a drainpipe that ends at an open floor drain.
(d) For NSR piping runs that are connected at both ends to SR piping, include the entire run of NSR piping.

For SLR, HNP has included all the connected NSR piping and supports, up to and including the first equivalent anchor beyond the SR/NSR interface, within the scope of SLR pursuant to 10 CFR 54.4(a)(2). The first equivalent anchor beyond the SR/NSR piping interface meets the criteria specified in Section 4 of Appendix F of NEI 95-10, Rev. 6. These piping segments are identified with notes on the boundary drawings. The aging effects for directly connected NSR piping are managed using the same programs that manage the SR piping. The associated NSR pipe supports are addressed in a commodity "spaces" approach, wherein all supports in the areas of concern, even those extending beyond the SR/NSR piping interface are included in the scope of SLR.

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

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

To address this requirement of 10 CFR 54.4(a)(2), HNP has chosen the preventive option for SLR. The preventive option involves identifying the NSR SSCs that have a spatial relationship such that failure could adversely impact the performance of a SR SSC intended function and including the identified NSR SSC within the scope of SLR without consideration of plant mitigative features. The concern is that age-related degradation of NSR SSCs could lead to adverse interactions with SR SSCs that have not been previously considered.

In order to identify spatial interactions that could result in SSCs meeting this criterion, the following approach and criteria were implemented. A list of buildings with SR components and commodities was assembled based on the plant controlled component database, drawings, and plant knowledge. These buildings are the turbine buildings, control buildings, reactor buildings, EDG building, and intake structure. The primary containments were not included because the SR components in these buildings are designed to remain functional in a post-accident atmosphere which would bound any adverse impacts from leakage or spray.

SLR walkdowns were then performed in accessible areas of these buildings looking for NSR equipment that could potentially impact SR equipment. In addition to the walkdowns, select SLR boundary drawings (SLRBDs) were also reviewed to identify NSR components in SR structures. As the result of a walkdown and SLRBD review, SSCs were discovered to be within the scope of SLR. Each mechanical system within the scope of SLR was reviewed to confirm that NSR SSCs within the system that meet the criteria of 10 CFR 54.4(a)(2) are in scope.

2.1.4.3 Retired Equipment

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

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

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

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

2.1.4.5 System and Structure Intended Functions

For the SSCs 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 TRs. The intended functions define the plant process, condition, or action that must be accomplished to perform or support a safety function for responding to a DBE (10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)) or to perform or support a specific requirement of one 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. For example, the residual heat removal (RHR) system is considered to be in the scope of SLR because it is required to perform the intended function of delivering cooling water to the reactor coolant system during the injection phase of a loss of coolant accident (LOCA) to support core cooling. The ultimate 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.

2.1.4.6 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. The mechanical system boundaries are depicted on the SLRBDs included in each mechanical system report. The in-scope boundaries of the mechanical components in the mechanical systems that are required to perform or support SR functions (10 CFR 54.4(a)(1)) or that are required to demonstrate compliance with one of the five regulated events (10 CFR 54.4(a)(3)) are shown highlighted in green on each applicable boundary drawing. NSR mechanical systems that are required for functional support of equipment that is included in the scope of LR for 10 CFR 54.4(a)(1) are also highlighted in green on each applicable boundary drawing. NSR mechanical components that are included within the scope of LR because their failure could prevent the accomplishment of a SR function due to potential spatial interaction are shown highlighted in red on each applicable boundary drawing.

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 to determine which SCs 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 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.

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 TR. These mechanical systems in the scope of SLR are grouped into one of the following categories:

- Reactor Vessel, Internals and 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 TR.

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 method for determining which SCs are subject to AMR include the following:

- Identify all SCs within that system based on design drawings, original license renewal (LR) documents, the safety component list from the SED, and from the controlled component database
- Define system evaluation boundaries and eliminate SCs not within the scope of SLR (i.e., not required to perform 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.
- NSR mechanical components and piping segments beyond the SR/NSR boundaries that have the intended function of ensuring structural integrity of the attached SR components under CLB design loading conditions are in the scope of SLR per 10 CFR 54.4(a)(2).
- In addition, NSR SCs that may not be directly connected to SR SCs whose failure could prevent the performance of a SR system intended function are in the scope of SLR per 10 CFR 54.4(a)(2). The concern is that age-related degradation of the NSR SCs could adversely impact NSR SCs through spatial interaction. These NSR SCs are highlighted in red on the applicable SLRBD and are documented in the relevant screening and AMR TR.
- Components needed to support each of the 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 not including a component that is assigned to the system and within the SLR boundary is explained in the screening and AMR TR.
- 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 (replaceable) 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 TR.

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 include the EDGs and air compressor skids. 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 TRs. 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 SC is evaluated in a screening and AMR TR. The structures in the scope of SLR are grouped into one of the following categories:

- Primary Containment
- Miscellaneous Structural Commodities

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 FSARs, 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. The determination of whether a passive, in-scope SC has a qualified life or specified replacement time period was based on a review of plant-specific information, including the controlled component database, maintenance programs and procedures, vendor manuals, and plant operating experience (OE).

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 Commodities.

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 controlled component database.
- 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. HNP 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 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).
Electrical continuity	Provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals.

Table 2.1-1
Passive Structure/Component Intended Function

Intended Function	Definition
Emergency cooling water source	Provide source of cooling water for plant shutdown.
Expansion/separation	Provide for thermal expansion and/or seismic separation.
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.
Gaseous release path	Provide path for release of filtered and unfiltered gaseous discharge.
Heat sink	Provide heat sink during SBO or DBAs.
Heat transfer	Provide heat transfer.
HELB barrier	Provide shielding against HELBs.
Holdup and plate-out	Provide post-accident containment, plate-out of iodine, and holdup (for radioactive decay) of iodine and non-condensable gases before release.
Impingement shielding	Provide shielding for jet impingement.
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.
Leakage boundary (spatial)	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 with 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, provide containment isolation for fission product retention, or provide pressure relief for relief valves.
Shelter, protection	Provide shelter/protection to in-scope components.
Shielding	Provide shielding against radiation.
Shutdown cooling water	Provide source of cooling water for plant shutdown.
Spray	Convert fluid into spray.
Structural integrity (attached)	NSR components that maintain mechanical and structural integrity to provide structural support to attached SR SSCs.
Structural pressure barrier	Provide pressure boundary or essentially leak-tight barrier to protect public health and safety in the event of any postulated DBEs.

Table 2.1-1
Passive Structure/Component Intended Function

Intended Function	Definition
Structural support	Provide structural and/or functional support to SR and/or NSR components.
Throttle	Provide flow restriction.
Water retaining boundary	Provide a water-retaining boundary so that flow of water between a barrier or seal is prevented.

2.1.5.5 Stored Equipment

The HNP CLB does not take credit for stored equipment or making repairs to equipment that meet the scoping criteria identified in 10 CFR 54.4(a). For FP safe shutdown, the HNP NFPA 805 NSCA represents the SSA. That report was reviewed and confirmed that the FP program does not take credit for post-fire repair of plant equipment or use of stored equipment. As such, there are no stored components or equipment included within the scope of SLR.

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 typically treated as subcomponents of their associated structure. These consumables are typically 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 or preventive maintenance items 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 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 codes, technical specifications, or site approved programs as described in the FP screening and AMR TR.

2.1.6 Interim Staff Guidance Discussion

As discussed in NEI 17-01 and NUREG-2191, the NRC has encouraged applicants to address SLR Interim Staff Guidance (ISG) documents in the SLRA and to consider these as OE. At the time of submittal of this SLRA, there are no SLR-ISGs that are not reflected in the July 2023 draft Revision 1 versions of NUREG-2191 and NUREG-2192. Future SLR-ISGs will be evaluated as OE.

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 1.6.15), 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 ensure they did not involve aging effects for SCs subject to AMR or time-limited aging analysis (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 HNP, 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 LOCA. This issue is not applicable to HNP (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 TLAAs. 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 the 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. This issue is now closed (Reference ML20260H122). The NRC documented the close-out of the HNP response for the reevaluated flooding hazard portion of the 10 CFR 50.54(f) letter in ML18030B076.

Thus, there are no GSIs involving aging effects for SCs subject to an AMR or TLAA evaluations that are relevant to the 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 HNP Units 1 and 2 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

HNPs IPA methodology consists of scoping, screening, and AMRs. Table 2.2-1 lists the systems, structures and commodity groups that were evaluated to determine if they are 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	HNP System Name	In-scope for SLR	Section
Reactor Vessel, Internals, and Reactor Coolant System			
Nuclear Boiler System	Nuclear Boiler System	Y	2.3.1.1
Reactor Pressure Vessel	Reactor Pressure Vessel	Y	2.3.1.3
Reactor Recirculation System	Reactor Recirculation System	Y	2.3.1.2
Reactor Vessel Internals	Reactor Vessel Internals	Y	2.3.1.4
	Fuel	Y	2.3.1.4
Engineered Safety Features			
Core Spray System	Core Spray System	Y	2.3.2.1
High Pressure Coolant Injection System	High Pressure Coolant Injection System	Y	2.3.2.2
Post LOCA Hydrogen Recombiners System (Unit 2 Only)	Post LOCA Hydrogen Recombiners System	Y	2.3.2.3
Primary Containment Purge and Inerting Systems	Primary Containment Purge and Inerting System	Y	2.3.2.4
Reactor Core Isolation Cooling System	Reactor Core Isolation Cooling System	Y	2.3.2.5
Residual Heat Removal System	Residual Heat Removal System	Y	2.3.2.6
Standby Gas Treatment System	Standby Gas Treatment System	Y	2.3.2.7
Standby Liquid Control System	Standby Liquid Control System	Y	2.3.2.8
Auxiliary Systems			
Bulk Gas System	Bulk Gas System	N	N/A
Circulating Water Structures HVAC	Circulating Water Structures HVAC	N	N/A
Circulating Water System	Circulating Water System	N	N/A
Compressed Air System	Compressed Air System	N	N/A
Condensate Transfer & Storage System	Condensate Transfer and Storage System	Y	2.3.3.1

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	HNP System Name	In-scope for SLR	Section
Condensate Tube Cleaning System	Condensate Tube Cleaning System	N	N/A
Containment Atmosphere Cooling System	Containment Atmosphere Cooling System	Y	2.3.3.3
Control Building Heating, Ventilation and Air Conditioning (HVAC) System	Control Building HVAC System	Y	2.3.3.4
Control Rod Drive System	Control Rod Drive System	Y	2.3.3.2
Demineralized Water Supply	Demineralized Water Supply	Y	2.3.3.5
Drywell Pneumatics System	Drywell Pneumatics System	Y	2.3.3.6
Emergency Diesel Generators System	Emergency Diesel Generators System	Y	2.3.3.7
	Fuel Oil System	Y	2.3.3.7
Environments Monitoring System	Environments Monitoring System	N	N/A
Excess Flow Check Valves (Unit 2 only)	Excess Flow Check Valves (Unit 2 only)	N	N/A
Excitation System	Excitation System	N	N/A
Fire Protection System	Fire Protection	Y	2.3.3.8
	Reactor Building Fire Protection Water	Y	2.3.3.8
	Turbine Building Fire Protection Water	Y	2.3.3.8
	Radwaste Building Fire Protection Water	Y	2.3.3.8
	Circulating Water Structures Fire Protection System	Y	2.3.3.8
	Other Buildings; Fire Protection System	Y	2.3.3.8
	Yard/Offsite Structures; Fire Protection System	Y	2.3.3.8
	Control Building; Fire Protection System	Y	2.3.3.8
Fuel Gas	Fuel Gas	N	N/A
Fuel Pool Cooling and Cleanup System	Fuel Pool Cooling and Cleanup System	Y	2.3.3.9
Generator	Generator	N	N/A
Generator Cooling System	Generator Cooling System	N	N/A
Gland Seal, Holdup, and Steam Seal	Gland Seal, Holdup, and Steam Seal	N	N/A
Hydrogen Recombining System	Hydrogen Recombining System	N	N/A
Hydrogen Seal System	Hydrogen Seal System	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	HNP System Name	In-scope for SLR	Section
Hydrogen Water Chemistry	Hydrogen Water Chemistry	N	N/A
Instrument Air System	Service Air System	Y	2.3.3.10
	Instrument Air System	Y	2.3.3.10
Makeup Demineralizer	Caustic	N	N/A
	Acidic	N	N/A
Moisture Extraction System	Moisture Extraction System	N	N/A
Nitrogen Blanket System	Nitrogen Blanket System	N	N/A
Non-Safety Affecting Safey-Related Systems	Decay Heat Removal	Y	2.3.3.11
	Electro-Hydraulic Control System	Y	2.3.3.11
	Lube Oil System	Y	2.3.3.11
	Turning Gear System	N	N/A
	Plant Hot Water Heating System	Y	2.3.3.11
	Reactor Building and Radwaste Building Chilled Water System	Y	2.3.3.11
	Reactor Building; Domestic Water	N	N/A
	Control Building Chilled Water System	Y	2.3.3.11
	Radioactive Equipment and Floor Drain System	Y	2.3.3.11
	Radioactive Drain System	N	N/A
	Other Buildings; Domestic Water	Y	2.3.3.11
	Yard/Offsite Structures; Domestic Water	Y	2.3.3.11
	Control Building; Domestic Water	Y	2.3.3.11
	Control Building; Sanitary Drain System	Y	2.3.3.11
	Control Building; Equipment, Floor Drain System (radioactive)	Y	2.3.3.11
	Radwaste Building; Equipment, Floor Drain System (radioactive)	N	N/A
	Radwaste Building; Domestic Water	N	N/A
	Turbine Building; Chilled Water System	N	N/A
	Turbine Building; Domestic Water	N	N/A
	Turbine Building; Equipment, Floor Drain System (radioactive)	N	N/A
Outside Structures HVAC System	Outside Structures HVAC System	Y	2.3.3.21
Plant Auxiliary Boiler and Heating System	Plant Auxiliary Boiler and Heating System	N	N/A
Pre-Operation Cleanup System	Pre-Operation Cleanup System	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	HNP System Name	In-scope for SLR	Section
Primary Containment Chilled Water System (Unit 2 Only)	Primary Containment Chilled Water System (Unit 2 Only)	Y	2.3.3.12
Process Radiation Monitoring System	Process Radiation Monitoring System	Y	2.3.3.13
Radwaste Building HVAC	Radwaste Building HVAC	N	N/A
Radwaste System	Radwaste System	Y	2.3.3.14
Reactor Building Closed Cooling Water System	Reactor Building Closed Cooling Water System	Y	2.3.3.15
Reactor Building HVAC System	Reactor Building HVAC System	Y	2.3.3.16
Reactor Water Cleanup System	Reactor Water Cleanup System	Y	2.3.3.17
Sampling System	Sampling System	Y	2.3.3.18
Service Water System	Plant Service Water System	Y	2.3.3.19
	Screen Wash System	Y	2.3.3.19
Torus Water Cleanup System	Torus Water Cleanup System	Y	2.3.3.20
Turbine Building Closed Cooling Water System	Turbine Building Closed Cooling Water System	N	N/A
Turbine Building HVAC	Turbine Building HVAC	N	N/A
Water Treatment System	Water Treatment System	N	N/A
Zinc Injection Passivation System	Zinc Injection Passivation System	N	N/A
Steam and Power Conversion Systems			
Condensate and Feedwater System	Condensate and Feedwater System	Y	2.3.4.1
	Main Condenser System	Y	2.3.4.1
Extraction Steam System	Extraction Steam System	N	N/A
Main Steam System	Main Steam System	Y	2.3.4.2
	Aux Drains and Vent System	Y	2.3.4.2
Off-Gas System	Off-Gas System	N	N/A
Reheat System	Reheat System	N	N/A
Turbine and Auxiliaries	Turbine and Auxiliaries	N	N/A
Containments, Structures, and Component Supports			
Miscellaneous Structural Commodities	Access Doors Systems	Y	2.4.2
	Atmosphere Monitoring Building	N	N/A
	Barge Dock	N	N/A
	Chemical	N	N/A
	Circulating Water Structures	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	HNP System Name	In-scope for SLR	Section
	Circulating Water Structures Cranes, Hoists, Elevators	N	N/A
	Conduits, Raceways, and Trays	Y	2.4.2
	Control Building	Y	2.4.4
	Control Building; Cranes, Hoists, Elevators	N	N/A
	Control Building; Roof, Tornado Vents	Y	2.4.2
	Cooling Tower	N	N/A
	Counting Room Equipment Radio Chem Lab	N	N/A
	Demineralizer House	N	N/A
	Diffusion Discharge Structure	N	N/A
	Ducts, Cable Trenches	Y	2.4.2
	EDG Building	Y	2.4.6
	Equipment Supports	N	N/A
	Fencing	N	N/A
	Fire Barrier Commodity Group[1]	Y	2.4.7
	Fire Protection Valve House	N	N/A
	Fuel Pool	Y	2.4.2
	Fuel Servicing Equipment	Y	2.4.5
	Health Physics Lab	N	N/A
	Hydrogen Housing	N	N/A
	Instrument Calibration and Decontamination Rooms	N	N/A
	Insulation System	Y	2.4.2
	Intake Structure	Y	2.4.8
	In-Vessel Servicing Equipment (Unit 1 Only)	Y	2.4.5
	Main Stack	Y	2.4.9
	Meteorological Building	N	N/A
	Microwave Tower and Building	N	N/A
	Miscellaneous Hoist	Y	2.4.5
	Other Buildings	N	N/A
	Other Buildings; Cranes, Hoists, Elevators	N	N/A
	Other Buildings; Sanitary Drain System	N	N/A
	Piping Specialties	Y	2.4.2
	Radwaste Building	Y	2.4.10
	Radwaste Building Cranes, Hoists, Elevators	N	N/A
	Radwaste Building Sanitary Drain System	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	HNP System Name	In-scope for SLR	Section
	Radwaste Building Storm Drains	N	N/A
	Railroads	N	N/A
	Reactor Building	Y	2.4.11
	Reactor Building Cranes, Hoists and Elevators System	Y	2.4.2
	Reactor Building Penetrations	Y	2.4.2
	Reactor Building Sanitary Drain System	N	N/A
	Reactor Building Storm Drains	N	N/A
	Reactor Building Tornado Vents System	Y	2.4.2
	Reactor Vessel Servicing Equipment	Y	2.4.5
	Rebuild Facility	N	N/A
	Refueling Equipment System	Y	2.4.5
	Roads and Walks	N	N/A
	Sanitary Drain Treatment System	N	N/A
	Security Building (Unit 1)	N	N/A
	Servicing Aids	N	N/A
	Short Term Radwaste Storage Building	N	N/A
	Spent Fuel Dry Storage	Y	2.4.2
	Start-up Equipment	N	N/A
	Storage Equipment Spent Fuel Racks	Y	2.4.11
	Switch House	N	N/A
	Switchyard Fire Protection Valve House	N	N/A
	Switchyard Structures[1]	Y	2.4.12
	Temporary Construction	N	N/A
	Tornado Vents (Unit 2)	Y	2.4.11
	Traveling Water Screens/Trash Racks System	Y	2.4.8
	Turbine Building	Y	2.4.13
	Turbine Building Cranes, Hoists, Elevators	N	N/A
	Turbine Building Roof, Tornado Vents	N	N/A
	Turbine Building Sanitary Drain System	N	N/A
	Turbine Building, Control, and Diesel Generator Building Storm Drains	N	N/A
	Under Reactor Vessel Servicing Equipment	N	N/A
	Visitor Center	N	N/A
	Water Monitoring Building and Systems	N	N/A
	Yard Drainage	N	N/A
	Yard/Offsite Structures	Y	2.4.14
	Yard/Offsite Structures; Elevator Hoists	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	HNP System Name	In-scope for SLR	Section
Primary Containment	Drywell to Refueling Basin Expansion Bellows	Y	2.4.1
	Primary Containment	Y	2.4.1
Electrical and I&C Systems			
Electrical Commodities	230Kv Substation	Y	2.5.1
	Analog Transmitter Trip System (ATTS)	Y	2.5.1
	Area Radiation Monitoring System	N	N/A
	Auto-Transformer	N	N/A
	Aux Grounding System	Y	2.5.1
	Breakers	N	N/A
	Cabinets and Panel Boards	Y	2.5.1
	Cable	Y	2.5.1
	Circulating Water Structures Lighting	N	N/A
	Communications Systems (Carrier and Microwave)	N	N/A
	Computer - Nuclear Steam Supply	N	N/A
	Computer - Power Systems Controls	N	N/A
	Control Building; Lighting	N	N/A
	Control Switches	Y	2.5.1
	Coupling Capacitors	N	N/A
	Current Limiting Reactors	N	N/A
	DC Electrical System	Y	2.5.1
	DC Instrument and Control Power	Y	2.5.1
	Drywell Electrical Penetrations	Y	2.5.1
	Electric Boiler	N	N/A
	Electrical Penetrations	Y	2.5.1
	Emergency Response Facilities System	Y	2.5.1
	Feedwater Control System	Y	2.5.1
	Fire Protection	N	N/A
	Fission Products Monitoring System	Y	2.5.1
	Generator and Aux	N	N/A
	Generator and Aux	Y	2.5.1
	Generator Bus	N	N/A
	Heat Trace System	Y	2.5.1
	HP Camera System	N	N/A
	In-Plant Auxiliary Control Panels System	Y	2.5.1
	Instruments	N	N/A
	Isolated Phase Bus	N	N/A
	Lightning Arrestors	N	N/A
	Load Centers	Y	2.5.1

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	HNP System Name	In-scope for SLR	Section
	Load Equipment	N	N/A
	Local Starters	Y	2.5.1
	Loose Part Monitoring	N	N/A
	Main Control Room Panels System	Y	2.5.1
	Metal Clad Switchgear	Y	2.5.1
	Miscellaneous Controls	N	N/A
	Miscellaneous Equipment	N	N/A
	Miscellaneous Equipment and Welding Outlets	N	N/A
	Miscellaneous Equipment and Welding Outlets	N	N/A
	Motor Control Centers	Y	2.5.1
	Motors	N	N/A
	Network Communication (Intra-plant)	N	N/A
	Neutron Monitoring System	Y	2.5.1
	Non Appendix "R" Emergency Lights	N	N/A
	Nuclear Instrument Grounding System and Equipment Supports	N	N/A
	Nuclear Steam Supply Shutoff System	Y	2.5.1
	Nuclear Steam Supply System Controls	N	N/A
	Other Buildings; Lighting	N	N/A
	Plant AC Electrical System	Y	2.5.1
	Plant Communications System	N	N/A
	Potential Transformers	N	N/A
	Power Cable and Control	Y	2.5.1
	Power Transformers System	Y	2.5.1
	Power Transmission System; General	Y	2.5.1
	Primary Containment Isolation System	Y	2.5.1
	Protective Relaying	Y	2.5.1
	Radwaste Building Lighting	N	N/A
	Reactor Building Lighting	N	N/A
	Reactor Protection System	Y	2.5.1
	Relaying	N	N/A
	Remote Shutdown System	Y	2.5.1
	Seismic Measurement Equipment/Seismic Equipment	N	N/A
	Special Cable	Y	2.5.1
	Standby Power Systems	Y	2.5.1
	Startup Transformers Secondary Buses	Y	2.5.1
	Station Transformers	Y	2.5.1
	Supplemental Power	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	HNP System Name	In-scope for SLR	Section
	Supplemental Power Cabinets and Panel Boards	N	N/A
	Supplemental Power Disconnect Switches	N	N/A
	Supplemental Power Load Centers	N	N/A
	Supplemental Power Local Starters	N	N/A
	Supplemental Power Metal Clad Switchgear	N	N/A
	Supplemental Power Motor Control Centers	N	N/A
	Supplemental Power Transformers	N	N/A
	Switch House Equipment	N	N/A
	Switches	N	N/A
	Traveling Incore Probe System	N	N/A
	Turbine Building Leak Detection System	Y	2.5.1
	Turbine Building Lighting	N	N/A
	Underground Electrical Cathodic Protection and Inground Pullbox and Cable Duct System	N	N/A
	Uninterruptable AC Power Supplies	Y	2.5.1
	Yard/Offsite Structures Lighting	N	N/A

Notes:

1) These structures do not have HNP system numbers but are added to this table to better align with NUREG-2191 and be consistent with the breakdown of structures in Section 2.

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. These components and component groups are 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 Vessel, Internals, and 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)

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

2.3.1.1 Nuclear Boiler System

<u>Description</u>

The nuclear boiler system is composed of several components and subsystems that are required to generate steam. Functions provided by the nuclear boiler system include supplying feedwater to the reactor, transporting steam from the reactor, reactor overpressure protection, and some reactor control and/or ESF functions. The nuclear boiler system is in operation any time the plant is in operation. Most of the major components in the system are part of the reactor coolant pressure boundary.

The system contains the following major components:

- Main steam lines (MSLs)
- Safety relief valves (SRVs)
- Main steam isolation valves (MSIVs)
- Feedwater lines
- Feedwater line check valves
- Instrumentation and controls

<u>Boundary</u>

The nuclear boiler system is shown on the following SLRBDs:

- H-16061-SLR
- H-16062-SLR
- H-16063-SLR
- H-16064-SLR
- H-16066-SLR
- H-16188-SLR
- H-16199-SLR
- H-16329-SLR

- H-16330-SLR
- H-16331-SLR
- H-16332-SLR
- H-16334-SLR
- H-26000-SLR
- H-26001-SLR
- H-26003-SLR
- H-26006-SLR
- H-26009-SLR
- H-26014-SLR
- H-26015-SLR
- H-26018-SLR
- H-26020-SLR
- H-26023-SLR
- H-26036-SLR
- H-26077-SLR
- H-26189-SLR
- H-26384-SLR

The nuclear boiler system also interfaces with numerous systems that make-up the reactor coolant pressure boundary. The SLRBDs that show this interface are as follows:

SBLC Interface:
H-16061-SLR: Starts at 1C41F006 (E-2) and continues to the reactor pressure vessel (RPV) (G-1) on H-16063-SLR (J-6)
H-26009-SLR: Starts at 2C41F006 (E-2) and continues to the RPV (G-1) on H-26001-SLR (J-6)

Feedwater Interface:
H-16062-SLR: Starts at 1B21F032A&B (F-1) and continues to the RPV
H-26000-SLR: Starts at 2B21F077A&B (F-1) and continues to the RPV

Main Steam (MS) Interface:
H-16062-SLR: Starts at the RPV (C-5) typical four places and stops at 1B21F028A-D (C-9)
H-26000-SLR: Starts at the RPV (C-5) typical four places and stops at 2B21F028A-D (C-9)

Control Rod Drive (CRD) Interface:
H-16064-SLR: Includes the CRD mechanism to valves 1C11F101 and 1C11F102
H-26006-SLR: Includes the CRD mechanism to valves 2C11F101 and 2C11F102

Reactor Water Cleanup (RWCU) Interface:
H-16188-SLR: Starts at "From Reactor" (C-1) and "From Bottom Head Drain of Reactor" (D-2) of H-16063-SLR and stops at 1E21N004 (A-3) of H-16188-SLR
H-26018-SLR: Starts at "From Reactor" (C-1) and "From Bottom Head Drain of Reactor" (D-2) of H-26001-SLR and stops at 2E21N004 (A-3) of H-26018-SLR
H-16188-SLR: Starts at 1E21F004A&B and continues to the RPV, H-16062-SLR (G-4), typical 2 places
H-26018-SLR: Starts at 2E21F004A&B and continues to the RPV, H-26000-SLR (G-4), typical 2 places

High Pressure Coolant Injection (HPCI) Interface:
H-16332-SLR: Starts at the MS piping of H-16062-SLR (C-6) and stops at 1E41F003 on H-16332-SLR (C-3); included are instrumentation lines that stop at the excess flow check valves,1E41F024A-D
H-26020-SLR: Starts at the MS piping of H-26000-SLR (C-6) at two places and stops at 2E41F003 on H-26020-SLR (C-3); included are instrumentation lines that stop at the excess flow check valves, 2E41F024A-D

Reactor Core Isolation Cooling (RCIC) Interface:
H-16334-SLR: Starts at the MS piping of H-16062-SLR (C-6) and stops at 1E51F008 on H-16334-SLR (C-6); included are instrumentation lines that stop at the excess flow check valves, 1E51N058A-D
H-26023-SLR: Starts at the MS piping of H-26000-SLR (C-6) and stops at 2E51F008 on H-16334-SLR (C-6); included are instrumentation lines that stop at the excess flow check valves, 2E51N058A-D

Recirculation Interface:
H-16066-SLR: Starts at the RPV bottom head drain and continues to the radwaste system
H-26003-SLR: Starts at the RPV bottom head drain and continues to the radwaste system

RHR Interface:
H-16329-SLR: Starts at 1E11F008 (D-2) and continues through 1E11F067 to H-16188-SLR, RWCU. In addition, the nuclear boiler boundary includes 1E11F017B and continues to the recirculation loop through 1E11F060B (D-3)
H-26014-SLR: Starts at 2E11F017B and continues to the recirculation loop through 2E11F050B (D-3)
H-16330-SLR: Starts at 1E11F017A and continues to the recirculation loop through 1E11F050A (D-3)
H-26015-SLR: Starts at 2E11F017B and continues to the recirculation loop through 2E11F050B (D-3)

Core Spray (CS) Interface:
H-16331-SLR: Starts at 1E21F004A&B and continues the RPV core nozzles on H-16062-SLR
H-16063-SLR (J-9) continues to valve 1E21F018C on H-16331 (A-5)
H-26018-SLR: Starts at 2E21F004A&B and continues the RPV core nozzles on H-26000-SLR
H-26001-SLR (J-9) continues to valve 2E21F018C on H-265018 (B-5)

Post Accident Reactor Coolant and Containment Atmosphere Sampling Interface:
H-16063-SLR (H-5) continues to H-26384-SLR (C-2) and ends at valves 1B21F112 (E-2) and 1B21F113 (F-2)
H-26001-SLR (J-5) and (H-5) continues to H-26384-SLR (C-11) and ends at valves 2B21F112 (E-10) and 2B21F113 (F-11)

Drywell Valve and Equipment Drainage Interface:
H-16062-SLR (E-3) and (F-3) continues to H-16199-SLR (B-4) and (D-2)
H-26000-SLR (E-3) and (F-3) continues to H-26077-SLR (A-5) and (D-3)

System Intended Functions

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

(1) The pressure control function prevents any overpressurization of the nuclear boiler system. It also provides automatic depressurization for small breaks to allow for low pressure coolant injection (LPCI) and CS operation.
(2) The nuclear boiler system is designed to maintain the reactor coolant pressure boundary integrity.
(3) The rod worth minimizer provides a means of enforcing procedural restrictions on preprogrammed control rod manipulations which are designed to limit rod worth to the values assumed in the plant accident analysis (design basis rod drop accident).
(4) Nuclear boiler instrumentation provides process information to the operator and signals to other systems in the nuclear power plant.

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, ATWS and SBO.

FSAR References

Unit 1 Sections 4.1, 4.4, 4.5, and 4.6
Unit 2 Sections 5.1, 5.2, 5.5, and 5.6

Components Subject to AMR

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

Table 3.1.2-1 provides the results of the AMR.

Table 2.3.1-1 - Nuclear Boiler System Components Subject to Aging Management Review

Component Type	Component Intended Function
Accumulator (MSIV and steam SRV)	Pressure boundary
Bolting (Class 1)	Mechanical closure
Bolting (Closure)	Mechanical closure
Condensing chamber	Pressure boundary
CRD return line welded connection	Pressure boundary
Flow venturi	Throttle

Component Type	Component Intended Function
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping and piping components greater than or equal to 4" nominal pipe size (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
Reactor coolant pressure boundary components subject to fatigue	Pressure boundary
Safety relief valve pilot body assembly	Pressure boundary
Thermowell	Pressure boundary
Vacuum breakers	Pressure boundary
Valve body	Pressure boundary
Valve body (Class 1)	Pressure boundary

2.3.1.2 Reactor Recirculation System

Description

The reactor recirculation system is one of two core reactivity control systems. The reactor recirculation system provides a variable moderator (coolant) flow to the reactor core for adjusting reactor power. The reactor recirculation system is part of the reactor coolant pressure boundary. Therefore, it also functions to maintain the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas.

Two parallel loops make up the reactor recirculation system, each containing a recirculation pump, suction and discharge block valves, piping, fittings, flow elements, and tubing that connects to instrumentation. The reactor recirculation system interfaces with the RHR and RWCU systems to provide a flow-path in support of shutdown cooling, LPCI, RWCU, and reactor water level control functions.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The reactor recirculation system boundaries are reflected on the SLRBDs listed below:

- H-16066-SLR
- H-26003-SLR

The boundary of the reactor recirculation system is shown on H-16066-SLR and H-26003-SLR. The system's boundary starts at the 28 inch nozzle connections at the reactor vessel and continues to the pump suction casing. The 28 inch pumps' discharge continues to two headers that consist of the five 12 inch lines that connect to the reactor vessel nozzles. The 20 inch connection in the suction piping supplies reactor coolant to the RHR system that is in-scope for the nuclear boiler system and shown on boundaries, H-16066-SLR and H-26003-SLR of the nuclear boiler system. In-scope piping to various instrumentation stops at the excess flow check valves upstream of the specific instrument; however, continues to the instrument connection in-scope with an intended function leakage boundary (spatial). The 3/4 inch piping to the sampling system is in-scope for the reactor recirculation system up to valves 1B31F019 and 2B31F020, Unit 1 and Unit 2, respectively.

System Intended Functions

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

(1) The reactor recirculation system is part of the reactor coolant pressure boundary; therefore, it also functions to maintain the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas.

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 ATWS.

FSAR References

Unit 1 Sections 4.3, 4.7.3, 7.2.3, and 7.8.4
Unit 2 Sections 5.5.1, 7.6.10, 8.4, 15.4.5, and 15C.4.3.5

Components Subject to AMR

Table 2.3.1-2 lists the reactor recirculation system component types that require an AMR and their associated component intended functions.

Table 3.1.2-2 provides the results of the AMR.

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

Component Type	Component Intended Function
Bolting (Class 1)	Mechanical closure
Bolting (Closure)	Mechanical closure
Flow nozzle (Class 1)	Pressure boundary
Heat exchanger (Reactor recirculating pump seal cooler housing)	Heat transfer Pressure boundary

Component Type	Component Intended Function
Heat exchanger (Reactor recirculating pump seal cooler outer cylinder)	Heat transfer Pressure boundary
Heat exchanger (Reactor recirculating pump seal cooler enclosing cylinder)	Heat transfer Pressure boundary
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial)
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
Valve body	Leakage boundary (spatial)
Valve body (Class 1)	Pressure boundary

2.3.1.3 Reactor Pressure Vessel

Description

The RPV consists of the top head enclosure, vessel shell, nozzles, nozzle safe ends, penetrations, bottom head, and support skirt and attachment welds. 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.

Boundary

Boundaries between the RPV and associated systems and components are typically drawn at the RPV interface. The evaluation boundaries for the RPV typically extends to the vessel nozzles connections to interfacing systems piping. The RPV boundaries are shown on various SLRBDs that are associated with the nuclear boiler system.

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 CRDs.
(2) Maintain reactor coolant pressure boundary.
(3) The RPV provides fission product retention capability.

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, SBO, and ATWS.

FSAR References

Unit 1 Section 4.2
Unit 2 Section 5.4

Components Subject to AMR

Table 2.3.1-3 lists the RPV component types that require an AMR and their associated component intended functions.

Table 3.1.2-3 provides the results of the AMR.

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

Component Type	Component Intended Function
Appurtenances	Pressure boundary Structural support
Attachments and connecting welds	Pressure boundary Structural support
Bottom head	Pressure boundary
Control rod drive return line nozzle	Pressure boundary
Control rod drive return line nozzle cap	Pressure boundary
Head spray cap	Pressure boundary
Nozzle	Pressure boundary
Nozzle safe ends	Pressure boundary
Nozzle safe ends and flanges	Pressure boundary
Reactor vessel nozzle (feedwater)	Pressure boundary
Penetrations: CRD housing stub tubes, in core monitor housings, instrumentation, SBLC/Core ΔP	Pressure boundary
Reactor vessel components with fatigue analysis	Pressure boundary Structural support
Reactor vessel flange leak-off line	Pressure boundary
Reactor vessel shells, nozzles, and welds in the beltline region of the reactor vessel	Pressure boundary

Component Type	Component Intended Function
Reactor vessel nozzle (feedwater)	Pressure boundary
Shell and closure heads	Pressure boundary
Support skirt and attachment welds	Structural support
Thermal sleeves	Direct flow
Top head	Pressure boundary
Top head instrument nozzle flange	Pressure boundary
Vessel head closure studs and nuts	Mechanical closure

2.3.1.4 Reactor Vessel Internals

Description

The reactor assembly consists of the RPV and the reactor vessel internals (RVI). The major reactor internal components are the core (fuel, channels, control blades, and instrumentation), the core support structure (including the core shroud, shroud head, separators, top guide, and core support), CS lines and spargers, the steam dryer assembly, jet pumps assemblies, and the CRD assemblies. The reactor internal structural elements are stainless steel or other corrosion resistant alloys.

The RVI provide proper coolant distribution to allow power operation without fuel damage and provide positioning and support for fuel assemblies to ensure control rod movement is not impaired. The CRD housing supports mitigate damage to the fuel barrier in the event a drive housing breaks or separates from the bottom of the reactor.

Boundary

The boundary between the RVI and the RPV is drawn at the inside stainless steel cladded wall of the reactor vessel. Components beyond and connected to the inside wall of the reactor vessel are considered components of the RVI.

The fuel assemblies, control rods and control blades are screened out as active or short-lived components. The shroud head assembly, steam separator assembly, feedwater sparger, SLC sparger and surveillance specimen holder are all not in the scope of SLR since they do not perform a SR intended function and their failure does not have the potential to adversely affect SR equipment.

System Intended Functions

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

(1) The RVIs provide proper coolant distribution to allow power operation without fuel damage and provide positioning and support for fuel assemblies to ensure control rod movement is not impaired.
(2) The CRD housing supports mitigate damage to the fuel barrier in the event a drive housing breaks or separates from the bottom of the reactor.

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

(1) The steam dryer assembly is a NSR component which is given a "structural integrity (attached)" function due to the impact to SR equipment from its potential failure.

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.

FSAR References

Unit 1 Sections 4.2.4 and C.3.2
Unit 2 Sections 4.2.2, 4.2.3, 4.5, 5.2, and 5.4

Components Subject to AMR

Table 2.3.1-4 lists the RVI component types that require an AMR and their associated component intended functions.

Table 3.1.2-4 provides the results of the AMR.

Table 2.3.1-4 - Reactor Vessel Internals Components Subject to Aging Management Review

Component Type	Component Intended Function
Control rod drive guide tube	Structural support
Control rod drive guide tube base	Structural support
Control rod drive housing	Structural support
Core plate access hole cover (mechanical design)	Direct flow
Core plate and core plate bolts	Structural support
Core plate DP/SLC line	Direct flow Pressure boundary
Core shroud	Direct flow Pressure boundary
Core spray lines and spargers: piping supports	Structural support
Core spray lines and spargers: spargers, headers, spray rings, pipe brackets, thermal sleeves	Direct flow Structural support
Core spray sparger nozzles	Spray
Fuel supports and control rod drive assemblies: orificed fuel support	Structural support Throttle
Instrumentation: intermediate range monitor dry tubes, source range monitor dry tubes, incore flux monitor guide tubes	Pressure boundary Structural support

Component Type	Component Intended Function
Jet pump assemblies: castings (diffuser, inlet elbow and nozzle mixer, section adapter, restrainer bracket, and transition piece)	Direct flow
Jet pump assemblies: riser pipe, mixing assemblies, diffuser and tailpipe, adapter top piece, sensing line, thermal sleeve (Unit 1)	Direct flow
Jet pump assemblies: adapter bottom piece, thermal sleeve (Unit 2)	Direct flow
Jet pump assemblies: holddown beams	Structural support
Jet pump assemblies: holddown beam bolts	Mechanical closure
Jet pump assemblies: riser brace arms	Structural support
Jet pump wedge surface	Structural support
Reactor vessel internal components	Direct flow Mechanical closure Pressure boundary Structural support Throttle
Reactor vessel internal components subject to fatigue	Direct flow Mechanical closure Pressure boundary Structural support Throttle
Shroud support structure: support plate (Unit 1), support cylinder, support gussets (Unit 1)	Direct flow Structural support
Shroud support structure: support plate (Unit 2)	Direct flow Structural support
Steam dryer	Structural integrity (attached)
Thermal sleeves	Direct flow
Top guide	Direct flow Structural support

2.3.2 Engineered Safety Features

2.3.2.1 Core Spray System

Description

The CS system is one of the ECCSs which protects the core from overheating in the event of a LOCA. The CS system is a low pressure system.

The system consists of two independent loops, each with a 100 percent capacity motor driven centrifugal pump and associated piping, valves and instrumentation necessary to perform the system intended functions. The CS system automatically sprays water onto the top of the fuel assemblies upon receipt of signals indicative of a LOCA.

The CS system provides protection to the core for large break scenarios with resultant low reactor pressure. In addition, protection can be afforded for small break scenarios in which the automatic depressurization system has initiated to lower reactor vessel pressure.

The system delivers cooling water at a sufficient flow rate to cool the core and prevent excessive fuel clad temperature. The system is maintained in a standby condition, powered by independent emergency auxiliary buses in the electrical distribution system.

To enable the CS system to make a quick startup and to minimize the water hammer possibilities during startup, the CS system discharge lines are maintained full of water by the jockey pump system. The jockey pump system consists of motor driven centrifugal pumps with the suction and discharge lines connected through piping and valves to the suction and discharge lines of the CS pumps, respectively. The jockey pump system also provides the same feature for the RHR system.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The CS system boundaries are reflected on the SLRBDs listed below:

- H-16135-SLR
- H-16328-SLR
- H-16331-SLR
- H-26018-SLR
- H-26019-SLR
- H-26042-SLR

The CS system interfaces with equipment drains, nuclear boiler, RHR, condensate storage and transfer, primary containment, and torus water cleanup (TWC) systems where system changes occur.

System Intended Functions

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

(1) The CS system protects the core by removing decay heat following a postulated design basis LOCA.
(2) The jockey pumps of the CS system are provided to keep the CS and LPCI lines full of water, thus minimizing the delay time for emergency core cooling and the possibility of water hammer.

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 and EQ.

FSAR References

Unit 1 Sections 6.3.3 and 6.4.2.4

Unit 2 Sections 5.2.1.1.11, 6.3.2.2.3, and 6.3.2.2.5

Components Subject to AMR

Table 2.3.2-1 lists the CS system component types that require an 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
Bolting (Closure)	Mechanical closure
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping elements	Leakage boundary (spatial)
Pump casing (Core spray)	Pressure boundary
Pump casing (Jockey)	Pressure boundary
Strainer (element)	Filter
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.2.2 High Pressure Coolant Injection System

Description

The HPCI system is one of the ECCSs. The HPCI system is designed to provide core cooling by coolant injection at normal operating pressure to provide RPV makeup for inventory loss due to a pipe break or LOCA that does not result in rapid RPV depressurization. It will fulfill this function until the RPV is depressurized to within the range of the low pressure systems discharge pressure. The system does so by supplying makeup coolant from one of two independent treated water sources: the condensate storage tank (CST) or the suppression pool, with the preferred source being the CST.

The HPCI system consists of turbine driven pumps, piping, valves, and controls that provide a complete and independent ECCS. A test line permits functional testing of the system during normal plant operation by allowing flow to be redirected back to the CST instead of the reactor vessel. A minimum flow bypass line bypasses pump discharge flow to the suppression pool to protect the pump in the event of a stoppage in the main discharge line. Reactor vessel steam is supplied to the turbine. Turbine exhaust steam is then dumped to the suppression pool.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The HPCI system boundaries are reflected on the SLRBDs listed below:

- H-16016-SLR
- H-16188-SLR
- H-16332-SLR
- H-16333-SLR
- H-16334-SLR
- H-26020-SLR
- H-26021-SLR
- H-26023-SLR
- H-26036-SLR
- H-26046-SLR
- H-26075-SLR
- H-26077-SLR

The HPCI system interfaces with the condensate storage and transfer, CRD, equipment drains, nuclear boiler, RCIC, RWCU, RHR, and primary containment purge and inerting systems where system changes occur.

System Intended Functions

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

(1) The HPCI system assures the reactor is adequately cooled to limit fuel-cladding temperature in the event of a small break in the RCS or a LOCA that does not result in rapid depressurization of the reactor vessel.
(2) The HPCI system maintains containment pressure boundary integrity at the containment penetrations including containment isolation.

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, ATWS and EQ.

FSAR References

Unit 1 Section 6.3.1
Unit 2 Section 6.3.2.2.1

Components Subject to AMR

Table 2.3.2-2 lists the HPCI system component types that require an 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
Blower housing (HPCI vacuum pump)	Leakage boundary (spatial)
Bolting (Closure)	Mechanical closure
Heat exchanger (Unit 1 lube oil cooler) channel head	Pressure boundary
Heat exchanger (Unit 1 lube oil cooler) tubes	Heat transfer Pressure boundary
Heat exchanger (Unit 1 lube oil cooler) tubesheet	Pressure boundary
Heat exchanger (Unit 1 lube oil cooler) shell	Pressure boundary
Heat exchanger (Unit 2 lube oil cooler) channel head	Pressure boundary
Heat exchanger (Unit 2 lube oil cooler) tubes	Heat transfer Pressure boundary
Heat exchanger (Unit 2 lube oil cooler) tubesheet	Pressure boundary
Heat exchanger (Unit 2 lube oil cooler) shell	Pressure boundary
Hose	Pressure boundary
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping elements	Leakage boundary (spatial)
Pump casing (HPCI condenser pump)	Leakage boundary (spatial)
Pump casing (HPCI main booster pump)	Pressure boundary
Pump casing (HPCI main pump)	Pressure boundary
Pump casing (HPCI turbine aux oil pump)	Pressure boundary
Pump casing (HPCI main oil pump)	Pressure boundary
Strainer (element)	Filter
Tank (HPCI barometric condenser)	Leakage boundary (spatial)
Tank (HPCI vacuum)	Leakage boundary (spatial)
Thermowell	Pressure boundary

Component Type	Component Intended Function
Turbine housing	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.2.3 Post LOCA Hydrogen Recombiners System (Unit 2 Only)

Description

The post LOCA hydrogen recombiner system for Unit 2 was originally designed to chemically recombine elemental hydrogen gas with atmospheric oxygen to lower the hydrogen gas concentration in containment to below explosive levels. It was determined that the containment atmospheric dilution (CAD) system is an acceptable method of controlling combustible gas concentrations within containment following a LOCA. Thus, the post LOCA hydrogen recombiner system has been removed. Piping from the torus and drywell was capped, and a small amount of piping and valves were retired in place per site procedures. Therefore, the only in-scope piping are the capped portions extending from the torus and drywell, which provide a primary containment boundary.

Unit 1 never utilized a hydrogen recombiner system, so it does not have similar piping within the scope of SLR.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The post LOCA hydrogen recombiners system boundaries are reflected on the SLRBD listed below:

- H-26068-SLR

System Intended Functions

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

(1) Maintain pressure boundary of the primary containment (torus and drywell).

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)):

None.

FSAR References

Unit 2 Section 6.2.5

Components Subject to AMR

Table 2.3.2-3 lists the post LOCA hydrogen recombiners system (Unit 2 only) component types that require an AMR and their associated component intended functions.

Table 3.2.2-3 provides the results of the AMR.

Table 2.3.2-3 - Post LOCA Hydrogen Recombiners System (Unit 2 Only) Components Subject to Aging Management Review

Component Type	Component Intended Function
Piping and piping components	Pressure boundary

2.3.2.4 Primary Containment Purge and Inerting System

Description

The primary containment purge and inerting system primarily provides and maintains an inert atmosphere in the primary containment for combustible gas control and FP. Plant technical specifications require that within 24 hours of reactor operation, the inerting system injects a sufficient amount of gaseous nitrogen into the drywell and torus so that the oxygen concentration falls below four percent by volume.

Major equipment for the purge and inerting system includes a purge air supply fan, liquid nitrogen storage tank, ambient vaporizer, steam vaporizer, vacuum breaker, valves, piping, controls, and instrumentation. The purge and inerting system provides containment vent paths to the standby gas treatment (SBGT) system that provides a vent path to the main stack for containment vent and purge operations. Primary containment valves within the primary containment system are included with the primary containment purge and inerting system.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The primary containment purge and inerting system boundaries are reflected in the SLRBDs listed below:

- H-16000-SLR
- H-16024-SLR
- H-16060-SLR
- H-16153-SLR
- H-16239-SLR
- H-16286-SLR
- H-16561-SLR
- H-26057-SLR
- H-26079-SLR
- H-26083-SLR
- H-26084-SLR
- H-26993-SLR

System Intended Functions

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

(1) The primary containment purge and inerting systems are designed to minimize the release of radioactive materials to the environment during accident conditions. The primary containment purge and inerting systems are the ESF systems for providing and maintaining an inert atmosphere in the primary containment for combustible gas control and FP.
(2) The primary containment relief valves are designed to maintain an external pressure of not more than 2 psi greater than the concurrent internal pressure. It is to prevent a collapse in either the drywell or torus as a result of the most rapid cooldown transient that can occur during operation or a postulated accident condition assuming the failure of a single active component.
(3) The containment/reactor building parameter monitoring portion of the system monitors and records drywell and torus safety parameters in the main control room (MCR). The parameters monitored include torus air and water temperature, water level, pressure and drywell pressure and temperature.
(4) The purge and inerting system provides a safety grade back-up supply of nitrogen gas for the drywell pneumatic system. The nitrogen gas provides motive force to the nuclear boiler system SRVs, MSIVs, and various other SR valves in the event of a loss of normal drywell pneumatic supply.

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 and EQ.

FSAR References

Unit 1 Sections 5.2.2.8 and 5.2.2.9
Unit 2 Sections 6.2.1.2.1.8 and 6.2.5.6.1

Components Subject to AMR

Table 2.3.2-4 lists the primary containment purge and inerting system component types that require an AMR and their associated component intended functions.

Table 3.2.2-4 provides the results of the AMR.

Table 2.3.2-4 - Primary Containment Purge and Inerting System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure

Component Type	Component Intended Function
Heat exchanger (Pressure buildup coil) tubes	Heat transfer Pressure boundary
Heat exchanger (Vaporizer) fins	Heat transfer
Heat exchanger (Vaporizer) tubes	Heat transfer Pressure boundary
Hoses	Pressure boundary
Piping and piping components	Pressure boundary
Rupture disk	Pressure boundary
Tank (Liquid nitrogen storage)	Pressure boundary
Tank (Nitrogen tank jacket)	Structural integrity (attached)
Valve body	Pressure boundary

2.3.2.5 Reactor Core Isolation Cooling System

Description

The RCIC system is a high pressure coolant makeup system which supports reactor shutdown when the feedwater system is unavailable. The RCIC system provides the capability of maintaining the reactor in a hot standby condition for an extended period. Normally, however, the RCIC system is used until the reactor pressure is sufficiently reduced to permit use of the shutdown cooling mode of the RHR system.

The RCIC system consists of a turbine driven pump, piping, valves, and the instrumentation necessary to maintain the water level in the reactor vessel above the top of the active fuel should the reactor vessel be isolated from normal feedwater flow. Also included in the design of the RCIC system is a barometric condenser, vacuum pump, and condensate pumps to prevent steam from leaking into the RCIC Diagonal, which would lead to habitability concerns if a steam leak occurred.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The RCIC system boundaries are reflected in the SLRBDs listed below:

- H-16329-SLR
- H-16332-SLR
- H-16334-SLR
- H-16335-SLR
- H-26020-SLR
- H-26023-SLR
- H-26024-SLR
- H-26084-SLR

Major system interfaces are listed as follows:

Nuclear boiler system at 1E51F008 on drawing H-16334-SLR and 2E51F008 on drawing H-26023-SLR.

Condensate transfer and storage system at 1E51F511, 1E51F009, and 1E51F514 on drawing H-16334-SLR and 2E51F009 on drawing H-26023-SLR.

System Intended Functions

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

(1) Provide core cooling during reactor shutdown by pumping makeup water into the reactor vessel in case of a loss of flow from the main feed 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)):

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

FSAR References

Unit 1 Section 4.7
Unit 2 Sections 5.2.1.1.6 and 7.4

Components Subject to AMR

Table 2.3.2-5 lists the RCIC system component types that require an AMR and their associated component intended functions.

Table 3.2.2-5 provides the results of the AMR.

Table 2.3.2-5 - Reactor Core Isolation Cooling System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (RCIC lube oil cooler) channel head	Pressure boundary
Heat exchanger (RCIC lube oil cooler) shell	Pressure boundary
Heat exchanger (RCIC lube oil cooler) tubes	Heat transfer Pressure boundary
Heat exchanger (RCIC lube oil cooler) tubesheet	Pressure boundary
Hose	Pressure boundary
Orifice	Pressure boundary Throttle

Component Type	Component Intended Function
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping elements	Leakage boundary (spatial)
Pump casing (RCIC barometric condenser condensate)	Leakage boundary (spatial)
Pump casing (RCIC barometric condenser vacuum)	Leakage boundary (spatial)
Pump casing (RCIC)	Pressure boundary
Rupture disc	Pressure boundary
Steam trap	Leakage boundary (spatial) Pressure boundary
Strainer (element)	Filter
Tank (RCIC barometric condenser)	Leakage boundary (spatial)
Tank (RCIC vacuum)	Leakage boundary (spatial)
Thermowell	Leakage boundary (spatial) Pressure boundary
Turbine casing (RCIC)	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.2.6 Residual Heat Removal System

Description

The RHR system is composed of several components and subsystems which are required to:

- Restore and maintain reactor vessel water level after a LOCA;
- Reduce temperature and pressure inside the containment after a LOCA;
- Remove airborne particulates in the drywell after a LOCA;
- Remove heat from the suppression pool water; and
- Remove decay and residual heat from the reactor core to achieve and maintain a cold shutdown condition.

The RHR system consists of four pumps and two heat exchangers divided into two loops of two pumps and one heat exchanger each, plus the associated instruments, valves, and piping. The RHR pumps take suction from the suppression pool or the reactor coolant recirculation loop. The pumps discharge into the recirculation loop, the suppression pool, the containment spray headers, the fuel pool cooling and cleanup (FPCC) system, depending upon the desired mode of system operation. The RHR system interfaces with the recirculation system to provide a flow path in support of shutdown cooling and LPCI. The RHR system interfaces with the reactor vessel and the reactor recirculation system, and with the nuclear boiler system at valves E11F043A&B&C&D and motor operated valves (MOVs) E11F017A&B, for both units, to form part of the reactor coolant pressure boundary; therefore, it also maintains the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas.

The RHR system is cooled through the heat exchangers by the RHR service water (RHRSW) system. The RHRSW takes suction from the Altamaha River. There are four RHRSW pumps per unit. The RHRSW system also serves as a standby coolant supply system by providing a means of injecting makeup water from the river to the RHR system to keep the core covered during an extreme emergency. For the purposes of SLR, the RHRSW system is included in the RHR system.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The RHR system boundaries are reflected in the SLRBDs listed below:

- D-11004-SLR
- H-16002-SLR
- H-16011-SLR
- H-16176-SLR
- H-16328-SLR
- H-16329-SLR
- H-16330-SLR
- H-16331-SLR
- H-16332-SLR
- H-16334-SLR
- H-16568-SLR
- H-21033-SLR
- H-21039-SLR
- H-26014-SLR
- H-26015-SLR
- H-26018-SLR
- H-26019-SLR
- H-26039-SLR
- H-26051-SLR
- H-28001-SLR

The RHR system interfaces with equipment drains and the reactor recirculation, containment spray, HPCI, RCIC, FPCC, and plant service water (PSW) systems where system changes occur.

System Intended Functions

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

(1) In LPCI mode, automatically restore and maintain the coolant inventory in the RPV so that the core is adequately cooled to preclude fuel cladding perforation and subsequent energy release due to a metal-water reaction.
(2) Provide containment spray/cooling to drywell and torus to remove airborne particulates in the drywell, reduce the temperature and pressure of the primary containment atmosphere post-LOCA, and maintain suppression pool temperature below that required to condense steam after a LOCA.
(3) Maintains containment pressure boundary integrity at the containment penetrations including containment isolation.

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.

FSAR References

Unit 1 Section 4.8
Unit 2 Section 5.5.7

Components Subject to AMR

Table 2.3.2-6 lists the RHR system component types that require an AMR and their associated component intended functions.

Table 3.2.2-6 provides the results of the AMR.

Table 2.3.2-6 - Residual Heat Removal System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (RHR pump seal cooler) channel head	Pressure boundary
Heat exchanger (RHR pump seal cooler) shell	Pressure boundary
Heat exchanger (RHR pump seal cooler) tubes	Heat transfer Pressure boundary
Heat exchanger (RHR) channel head with internal coating	Pressure boundary
Heat exchanger (RHR) shell	Pressure boundary
Heat exchanger (RHR) tubes	Heat transfer Pressure boundary
Heat exchanger (RHR) tubesheet with internal coating	Pressure boundary
Hose	Leakage boundary (spatial)
Motor casing (RHRSW pump)	Pressure boundary
Motor oil cooler (RHRSW pump) coils	Heat transfer Pressure boundary
Motor oil cooler (RHRSW pump) manifold	Pressure boundary
Nozzle	Spray

Component Type	Component Intended Function
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping elements	Leakage boundary (spatial)
Pump casing (RHR)	Pressure boundary
Pump casing (RHRSW)	Pressure boundary
Pump casings – Bowl assembly (RHRSW)	Pressure boundary
Strainer (body)	Pressure boundary
Strainer (element)	Filter
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.2.7 Standby Gas Treatment System

Description

The SBGT system is an ESF system for ventilation and cleanup of the primary and secondary containment during certain postulated DBAs, and meets the design, QA, redundancy, energy source, and instrumentation requirements for ESF systems. The SBGT system is also used as a normal means of venting the drywell.

The system consists of two, full capacity, identical, parallel air filtration assemblies (trains) enclosed within a Seismic Class 1 structure. The underground discharge pipe leading to the main stack is Seismic Class 1. The design for the Unit 1 and Unit 2 SBGT systems differ. The Unit 1 trains' discharge lines tie together into a single header for discharge to the main stack. The Unit 2 trains have separate headers for discharge to the main stack.

The major components of the SBGT system include redundant filter trains, control valves, backdraft dampers, fans, and control instrumentation. Each of the filtration assemblies and their respective components are designed for 100 percent capacity operation.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The SBGT system boundaries are reflected in the SLRBDs listed below:

- H-16020-SLR
- H-16024-SLR
- H-16174-SLR
- H-26078-SLR

- H-26084-SLR

The SBGT system interfaces with the reactor building HVAC system at the pipe/duct junction on H-16020-SLR (coordinate H-1).

System Intended Functions

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

(1) The SBGT system is designed to minimize the release of radioactive materials to the environment during accident conditions. The SBGT system is the ESF system for ventilation and cleanup of the primary and secondary containment during certain postulated DBAs.

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 regulation for EQ.

FSAR References

Unit 1 Section 5.3.2.3
Unit 2 Section 6.2.4

Components Subject to AMR

Table 2.3.2-7 lists the SBGT system component types that require an AMR and their associated component intended functions.

Table 3.2.2-7 provides the results of the AMR.

Table 2.3.2-7 - Standby Gas Treatment System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Fan housing	Pressure boundary
Filter housing	Pressure boundary
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Rupture disk	Pressure boundary
Valve body	Pressure boundary

2.3.2.8 Standby Liquid Control System

Description

The SBLC system consists of a low temperature sodium pentaborate solution storage tank, a test tank, a pair of full capacity positive displacement pumps, two explosive actuated shear plug valves, two accumulators, and the necessary piping, valves, and instrumentation. The SBLC system assures reactor shutdown, from full power operation to cold subcritical, by mixing a neutron absorber with the primary reactor coolant. The system is designed for the condition when an insufficient number of control rods can be inserted from the full power setting. The neutron absorber is injected within the core zone in enough quantity to provide enough margin for leakage or imperfect mixing.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The boundaries of the SBLC system are shown on the SLRBDs listed below:

- H-16061-SLR
- H-26009-SLR

The system interfaces with the nuclear boiler system at Unit 1 valve 1C41F006 shown on drawing H-16061-SLR coordinate E-2 and Unit 2 valve 2C41F006 shown on H-26009-SLR coordinate E-2.

The system interfaces with the demineralized water supply system at Unit 1 valve 1C41F009 shown on drawing H-16061-SLR coordinate A-8 and Unit 2 valve 2C41F009 shown on H-26009-SLR coordinate B-7.

System Intended Functions

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

(1) The SBLC system assures reactor shutdown from full power operation to cold subcritical (reactivity control) by mixing a neutron absorber with the primary reactor coolant.

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 and ATWS.

FSAR References

Unit 2 Section 4.2.3.4

Components Subject to AMR

Table 2.3.2-8 lists the SBLC system component types that require an AMR and their associated component intended functions.

Table 3.2.2-8 provides the results of the AMR.

Table 2.3.2-8 - Standby Liquid Control System Components Subject to Aging Management Review

Component Type	Component Intended Function
Accumulator (SBLC pump) with internal coating	Pressure boundary
Bolting (Closure)	Mechanical closure
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping elements	Leakage boundary (spatial)
Pump casing (Injection)	Pressure boundary
Tank (Storage tank)	Pressure boundary
Tank (Test tank)	Leakage boundary (spatial)
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3 Auxiliary Systems

2.3.3.1 Condensate Transfer and Storage System

Description

The condensate transfer and storage system consists of an aluminum storage tank (Unit 1), a stainless steel storage tank (Unit 2), two condensate transfer pumps, and the necessary piping and instrumentation to convey and monitor the water to various systems.

The CSTs are atmospheric storage tanks located outdoors. The tanks and transfer pumps are surrounded by a seismic category I and horizontal missile-proof retaining wall, integrally sized to hold the entire water inventory of each tank. With the exception of small instrument connections, a drain line, which is normally closed by a valve and a blind flange, and RCIC system and HPCI suction connections to the tanks, all other lines terminate inside the tanks above the 100,000 gallon level to ensure that RCIC and HPCI systems are not deprived of their minimum reserve storage requirements by other less essential systems. An overflow connection on each tank is piped to the radwaste system waste surge tank.

A single condensate transfer pump is required to furnish condensate water to various equipment in the reactor and radwaste building (RWB), except for the RCIC, HPCI, CRD, CS, and condenser hotwell transfer lines which draw directly from the tank. The introduction of a low pump discharge pressure signal will automatically start the standby pump and simultaneously initiate an alarm in the MCR. To accelerate the filling of the reactor well and dryer separator pool during refueling, both transfer pumps are operated in parallel.

The CSTs are maintained with a water level more than 15 ft above the tank bottom through the addition of demineralized water makeup. High tank level will alarm in the MCR. Should the level in the tank fall below a preset level, a low-level signal automatically switches the HPCI and RCIC pump suctions to the suppression pool. Pressure gauges are located at various points in the condensate transfer system for convenience in checking operating conditions.

A cross-connect line between HNP Unit 1 and HNP Unit 2 storage tanks provides the capability of transferring water between the two tanks, thereby increasing condensate storage capacity to either unit.

The preferred water source for the RCIC and HPCI systems is the CST. The design of the CSTs ensures 100,000 gallons of water are set aside for this supply. The HPCI and RCIC systems rely upon this volume of water during the response to SBO.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The condensate transfer and storage system boundaries are reflected on the SLRBDs listed below:

- H-16016-SLR
- H-26020-SLR
- H-26046-SLR

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

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

FSAR References

Unit 1 Section 11.9
Unit 2 Section 9.2.6

Components Subject to AMR

Table 2.3.3-1 lists the condensate transfer and storage system component types that require an AMR and their associated component intended functions.

Table 3.3.2-1 provides the results of the AMR.

Table 2.3.3-1 - Condensate Transfer and Storage System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (closure)	Mechanical closure
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Tank (Unit 1 condensate storage tank)	Pressure boundary
Tank (Unit 2 condensate storage tank)	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.2 Control Rod Drive System

Description

The CRD system controls gross changes in core reactivity by incrementally positioning neutron-absorbing control rods within the reactor core in response to manual control signals. It is also required to scram the reactor in emergency situations by rapidly inserting withdrawn control rods into the core in response to a manual or automatic signal. The CRD system consists of CRD mechanisms, ARI system, and the CRD hydraulic control units, interconnecting piping, instrumentation, and electrical controls.

The ARI system is a subsystem of the CRD system. It is a backup means of scramming the reactor by venting the scram air header. It is completely independent of the RPS and was installed for the purpose of reducing the probability of an ATWS event.

The CRD mechanism (drive) used for positioning the control rod in the reactor core is a double-acting, mechanically latched, hydraulic cylinder using water as its operating fluid. The drives are capable of inserting or withdrawing a control rod at a slow, controlled rate as well as providing rapid insertion when required. The individual drives are mounted on the bottom head of the RPV.

The CRD hydraulic system provides pressurized, demineralized water for the cooling and manipulation of the CRD mechanisms. In addition, the CRD system provides purge water for the RWCU pump and reactor recirculation pump seals.

Water enters the CRD system from the condensate header downstream of the condensate demineralizers (normal suction) or from the CST (alternate suction). The condensate header is the preferred suction source because the water contains less oxygen (deaerated) than water from the CST.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The boundaries of the CRD system are shown on the SLRBDs listed below:

- H-16016-SLR
- H-16064-SLR
- H-16065-SLR
- H-16066-SLR
- H-16239-SLR
- H-21037003-SLR
- H-26006-SLR
- H-26007-SLR
- H-26046-SLR

The CRD system interfaces with the following systems as listed below:

- Condensate transfer and storage system as shown on drawings H-16016-SLR and H-26046-SLR.
- Condensate and feedwater system as shown on drawings H-16065-SLR and H-21037003-SLR.
- Reactor recirculation system as shown on drawings H-16066-SLR and H-26003-SLR.
- Reactor vessel as shown on drawings H-16064-SLR and H-26006-SLR.
- Radwaste system as shown on drawings H-16176-SLR and H-26026-SLR.
- RWCU system as shown on drawing H-16188-SLR and H-26036-SLR.
- HPCI system as shown on drawings H-16332-SLR and H-26046-SLR.
- Reactor building closed cooling water (RBCCW) system as shown on drawings H-16009-SLR and H-26055-SLR.

System Intended Functions

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

(1) The CRD system in scram mode allows quick shutdown of the reactor in emergency situations by rapidly inserting withdrawn control rods into the core in response to a manual or automatic signal.

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, ATWS and SBO.

FSAR References

Unit 1 Section 7.2.3.5
Unit 2 Sections 4.2.3.2, 8.4, 15.4.5 and 15C.4.3.5

Components Subject to AMR

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

Table 3.3.2-2 provides the results of the AMR.

Table 2.3.3-2 - Control Rod Drive System Components Subject to Aging Management Review

Component Type	Component Intended Function
Accumulator (SCRAM)	Pressure boundary
Bolting (Closure)	Mechanical closure
Cylinder (N_2)	Pressure boundary
Filter (CRD pump suction)	Leakage boundary (spatial)
Filter (Drive water)	Leakage boundary (spatial)
Flow nozzle	Leakage boundary (spatial)
Heat exchanger (CRD pump bearing cooler) shell	Leakage boundary (spatial)
Orifice	Leakage boundary (spatial)
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Pump casing (Drive water)	Leakage boundary (spatial)
Rupture disk	Pressure boundary Pressure relief
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.3 Containment Atmosphere Cooling System

Description

The containment atmosphere cooling (CAC) system, which is also referred to as the primary containment (drywell) cooling system in the FSAR, uses fan coil units to provide cooling and maintain uniform temperatures in containment.

The CAC system is designed to perform the following NSR functions:

- With sufficient redundancy and separation of components to provide reliable operation under normal conditions and to ensure operation of the fans under emergency conditions.
- To control temperature and prevent thermal stratification in the drywell area.
- To optimize equipment performance by removal of heat dissipate from the plant equipment.

The Unit 1 and Unit 2 drywell fan coil units perform no active SR function. However, the Unit 1 fan coil units are classified as SR to support the pressure boundary of the PSW system. For Unit 2, the fan coil units are classified as SR to support the pressure boundary of the primary containment chilled water (PCCW) system. Thus the Unit 1 and 2 fan coil units are classified as SR to support the containment isolation and containment boundary SR function.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The CAC system boundaries are reflected on the SLRBD listed below:

- H-16007-SLR

The CAC system interfaces with the Unit 1 PSW system in various locations on drawing H-16007-SLR, and interfaces with the Unit 2 PCCW systems in various locations on H-26074-SLR. The CAC system Unit 2 drywell fan coil units are the components that interface with the PCCW system. The Unit 2 drywell fan coil units are evaluated in the PCCW system.

System Intended Functions

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

(1) Maintain the pressure boundary for the PSW system in containment.
(2) Maintain the pressure boundary for the PCCW system.

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

None.

FP, EQ, ATWS, and SBO functions (10 CFR54.4(a)(3)):

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

FSAR References

Unit 1 Section 5.2.2.7
Unit 2 Section 9.4.6.2.1

Components Subject to AMR

Table 2.3.3-3 lists the CAC system component types that require an AMR and their associated component intended functions.

Table 3.3.2-3 provides the results of the AMR.

Table 2.3.3-3 - Containment Atmosphere Cooling System Components Subject to Aging Management Review

Component Type	Component Intended Function
Heat exchanger (Drywell fan coil units) channel head	Pressure boundary
Heat exchanger (Drywell fan coil units) tubes	Pressure boundary

2.3.3.4 Control Building HVAC System

Description

The control building HVAC systems are designed with sufficient redundancy and separation of components to provide reliable operation under normal conditions and to ensure operation under emergency conditions of ventilation for the battery rooms and cooling for the LPCI inverter room.

The control building HVAC system is designed to perform the following functions:

- Provide temperature and air movement control for personnel comfort and equipment operation.
- Optimize equipment performance by the removal of heat dissipated from plant equipment.
- Provide an adequate supply of filtered fresh air for personnel.
- Minimize the possibility of exhaust air recirculation into the air intake.
- Assure a controlled environment for personnel safety and habitability in the control room during normal and accident conditions.
- Provide purging capability for removing radioactive and foreign material from the MCR environment.
- Detect and limit the introduction of radioactive material into the MCR.

The control building is served by both heating and A/C subsystems and a once-through ventilation subsystem. The A/C subsystems use direct expansion of chilled water cooling coils. Heating is provided by electric or hot water heating coils. The control room, computer room, water sampling room, chemistry laboratory and health physics area, and cold laboratory are the areas served by the heating and A/C subsystems. The LPCI inverter room, Vital A/C rooms and RPS motor-generator (MG) set rooms are served by separate coolers. All other areas of the control building are served by a once-through ventilation subsystem.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The control building HVAC system boundaries are reflected on the SLRBDs listed below:

- H-11609-SLR
- H-16040-SLR
- H-16041-SLR
- H-16042-SLR
- H-26093-SLR
- H-26116-SLR
- H-51178-SLR

- H-51179-SLR

The system interfaces with the instrument air system at Unit 1 valve 1Z41F100 shown on drawing H-16042-SLR coordinate G-1. The system interfaces with the PSW system as shown on drawing H-11609-SLR coordinates B-2, B-3, and B-4.

System Intended Functions

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

(1) The control building HVAC system assures a controlled environment for personnel safety and habitability in the control room during normal and accident conditions.
(2) The control building HVAC provides purging capability for removing radioactive and foreign material from the MCR environment.
(3) The control building HVAC detects and limits the introduction of radioactive material into the MCR.

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.

FSAR References

Unit 1 Section 10.9.3.6
Unit 2 Sections 6.4.1, 9.4.1, and 9.4.7

Components Subject to AMR

Table 2.3.3-4 lists the control building HVAC component types that require an AMR and their associated component intended functions.

Table 3.3.2-4 provides the results of the AMR.

Table 2.3.3-4 - Control Building HVAC System Components Subject to Aging Management Review

Component Type	Component Intended Function
Accumulator (Control room air)	Pressure boundary
Blower housing (Battery room emergency exhaust)	Pressure boundary
Blower housing (Control room air handling unit)	Pressure boundary
Blower housing (Control room booster fan)	Pressure boundary
Blower housing (Control room exhaust fan)	Pressure boundary

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Bolting (HVAC closure)	Mechanical closure
Drip pan	Leakage boundary (spatial)
Ducting and ducting components	Pressure boundary
Flexible connection	Pressure boundary
Heat exchanger (Control room A/C condenser unit) channel head with internal coating	Pressure boundary
Heat exchanger (Control room A/C condenser unit) fins	Heat transfer
Heat exchanger (Control room A/C condenser unit) shell	Pressure boundary
Heat exchanger (Control room A/C condenser unit) tubes	Heat transfer Pressure boundary
Heat exchanger (Control room A/C condenser unit) tubesheet	Pressure boundary
Heat exchanger (Control room air handling unit cooling coil) fins	Heat transfer
Heat exchanger (Control room air handling unit cooling coil) tubes	Heat transfer Pressure boundary
Heat exchanger (NSR coolers tubes)	Leakage boundary (spatial)
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Thermowell	Pressure boundary
Valve body	Pressure boundary

2.3.3.5 Demineralized Water Supply System

Description

The demineralized water supply system supplies water from the demineralized water storage tank to multiple systems and equipment at the site. The system is shared between both Hatch units. The system's containment isolation valves perform the only SR function, isolating containment. The system also is in scope of SLR due to the potential to leak or spray on SR components.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The demineralized water supply system boundaries are reflected on the SLRBDs listed below:

- H-11038-SLR

- H-11631-SLR
- H-16015-SLR
- H-16024-SLR
- H-26047-SLR

The demineralized water supply system has two boundaries with the purge and inerting system as shown on drawing H-16015-SLR. The SR function of these interfacing valves is containment isolation.

System Intended Functions

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

(1) The demineralized water supply system maintains containment pressure boundary integrity at the containment penetrations including containment isolation.

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.

FSAR References

Unit 2 Section 9.2.3

Components Subject to AMR

Table 2.3.3-5 lists the Demineralized Water Supply System component types that require an 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 Supply System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (closure)	Mechanical closure
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.6 Drywell Pneumatic System

Description

The drywell pneumatic system supplies motive gas to the following equipment inside the drywell:

- Reactor recirculation system sample line isolation valve
- RPV head vent valve
- CS system injection testable check valves and bypass valves
- PCCW system control valves
- RHR system LPCI check valves and bypass valves
- Nuclear boiler system SRVs and MSIVs

Except for the SRVs, pneumatic-operated devices contained in the drywell are designed for the fail-safe mode and do not require continuous gas supply under emergency or abnormal conditions. However, the piping and tubing to these components are required to maintain their pressure boundary to prevent drywell overpressurization.

A major portion of the drywell pneumatic system is primarily obsolete and not currently used. The control air is supplied from the nitrogen makeup system or instrument air system. The system components still exist in the plant but are isolated by valve alignment or the lines are physically cut and capped.

The drywell pneumatic system receives motive gas from the Unit 1 or Unit 2 nitrogen storage tanks during plant startup and normal operations, the instrument air system during plant shutdown, or the emergency nitrogen hookup stations. The system includes an air receiver, particulate filters, flow sensing elements, and various process piping, valves, and regulators.

Normally all system equipment upstream of the receiver tank is isolated, and system pressure is maintained by the nitrogen back-up supply with alternate supply through the instrument air supply system. Under emergency condition specific components in the drywell will be supplied control air from emergency nitrogen bottles.

Boundary

The boundary for the drywell pneumatic system is shown on the SLRBDs listed below:

- H-16011-SLR
- H-16062-SLR
- H-16066-SLR
- H-16286-SLR
- H-16299-SLR
- H-16329-SLR
- H-16330-SLR
- H-16331-SLR
- H-26000-SLR
- H-26003-SLR

- H-26014-SLR
- H-26015-SLR
- H-26018-SLR
- H-26066-SLR
- H-26081-SLR
- H-28023-SLR

System Intended Functions

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

(1) The drywell pneumatic system provides gas of suitable quality and pressure to supply essential equipment within the drywell requiring motive gas.
(2) The drywell pneumatic system maintains containment pressure boundary integrity at the containment penetrations including containment isolation.
(3) The drywell pneumatic system protects against the depletion of the nitrogen supply and the overpressurization of the drywell due to the rupture of the pneumatic header in the drywell.

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.

FSAR References

Unit 1 Section 10.19
Unit 2 Section 9.3.6

Components Subject to AMR

Table 2.3.3-6 lists the drywell pneumatic system component types that require an AMR and their associated component intended functions.

Table 3.3.2-6 provides the results of the AMR.

Table 2.3.3-6 - Drywell Pneumatic System Components Subject to Aging Management Review

Component Type	Component Intended Function
Air accumulator (Air receiver)	Pressure boundary
Bolting (Closure)	Mechanical closure
Filter housing	Pressure boundary
Hose	Pressure boundary

Component Type	Component Intended Function
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.7 Emergency Diesel Generators System

Description

The EDG is a diesel engine-driven electrical generator that provides a back-up source of electrical power to the emergency electrical bus in the event that the normal supply is unavailable. There are five EDGs for both HNP Units 1 and 2 supplying standby power to 4.16 kV essential buses: 1E, 1F, 1G of Unit 1; and 2E, 2F, and 2G of Unit 2. EDGs 2A and 2C supply buses 2E and 2G respectively. EDG 1B is shared between Units 1 and 2 and can supply power to either 1F or 2F. EDG 1B has a selector switch with “Unit 1 control” and “Unit 2 control” positions, depending on whether it is supplying bus 1F or 2F. EDGs 1A and 1C supply buses 1E and 1G, respectively.

The following is a description of each EDG subsystem:

Fuel supply storage and transfer subsystem
The EDG fuel oil system consists of five independent trains of equipment with each train supplying oil to its respective EDG. Each independent system contains an underground 40,000 gallon storage tank, day tanks, piping, transfer pumps, valves, and filters. The total storage capacity of the 40,000 gallon storage tanks is sufficient to operate four EDGs for 7 days at 3250 KW power operation.

Cooling water subsystem
The cooling water system is a closed-loop circulating water cooling subsystem designed to remove sufficient heat by supplying the required quantity of cooling water to permit the operation of the diesel engine at maximum load. The system removes heat from other subsystem via independent coolers; an air cooler, a lube oil cooler, and jacket cooler. Each cooling water subsystem includes an expansion tank for makeup water. Cooling water is supplied by PSW. During standby mode, the engine coolant is maintained at a preset temperature and is circulated through the diesel cooling system by a jacket coolant pump.

Lubrication subsystem
The lubrication system is a positive full-pressure lubrication subsystem designed to supply a continuous flow of oil to all surfaces requiring lubrication and to the pistons for cooling during EDG operation. During engine operation, an engine-driven oil pump circulates the oil throughout the engine. The diesel heat exchanger cools the lube oil via the PSW system. During standby periods, an electric motor-driven circulating pump (standby lubricating oil pump) draws oil from the engine sump, pumps it through an electric immersion heater, circulates it throughout the system, and returns it to the engine sump. This maintains a minimum oil temperature during standby to promote starting and to prevent extreme changes in lube oil viscosities.

Starting air subsystem
Each EDG is supplied with its own complete starting air subsystem. Each starting system consists of two redundant air compressors, two redundant air receivers, filters, and piping and valves to the EDG. Each air receiver is capable of supplying enough compressed air for a minimum of five engine starts. The air compressors are NSR and are not part of the SLR scope since the air receivers maintain adequate volume and pressure to meet the minimum five start requirement.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The boundary of the EDG system shown on the SLRBDs listed below:

- H-11037-SLR
- H-11631001-SLR
- H-11631002-SLR
- H-11638001-SLR
- H-11638002-SLR
- H-21074-SLR

The EDG system interfaces with the demineralized water system for makeup to the expansion tanks and PSW system at heat exchangers and associated components.

System Intended Functions

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

(1) Provide a reliable source of emergency power for SR loads in the event of a loss of offsite power.

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.

FSAR References

Unit 1 Sections 8.3 and 8.4.3
Unit 2 Sections 8.3, 9.5.4, 9.5.5, 9.5.6 and 9.5.7

Components Subject to AMR

Table 2.3.3-7 lists the EDG system component types that require an AMR and their associated component intended functions.

Table 3.3.2-7 provides the results of the AMR.

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

Component Type	Component Intended Function
Access hole cover	Shelter, protection
Bolting (Closure)	Mechanical closure
Filter housing	Pressure boundary
Heat exchanger (Jacket water) channel head	Pressure boundary
Heat exchanger (Jacket water) shell	Pressure boundary
Heat exchanger (Jacket water) tubes	Heat transfer Pressure boundary
Heat exchanger (Jacket water) tubesheet with internal coating	Pressure boundary
Heat exchanger (Lube oil) channel head	Pressure boundary
Heat exchanger (Lube oil) shell	Pressure boundary
Heat exchanger (Lube oil) tubes	Heat transfer Pressure boundary
Heat exchanger (Lube oil) tubesheet with internal coating	Pressure boundary
Heat exchanger (Scavenging air) channel head	Pressure boundary
Heat exchanger (Scavenging air) shell	Pressure boundary
Heat exchanger (Scavenging air) tubes	Heat transfer Pressure boundary
Heat exchanger (Scavenging air) tubesheet with internal coating	Pressure boundary
Heater (Jacket water standby) housing	Pressure boundary
Heater (Lube oil preheating) housing	Pressure boundary
Hose	Pressure boundary
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping elements	Leakage boundary (spatial) Pressure boundary
Pump casing (Air coolant jacket water)	Pressure boundary
Pump casing (Engine driven fuel oil)	Pressure boundary
Pump casing (Engine driven jacket water)	Pressure boundary

Component Type	Component Intended Function
Pump casing (Engine driven lube oil)	Pressure boundary
Pump casing (Fuel oil hand priming)	Pressure boundary
Pump casing (Fuel oil transfer)	Pressure boundary
Pump casing (Motor driven jacket water)	Pressure boundary
Pump casing (Motor driven lube oil)	Pressure boundary
Pump casing (Prelube oil)	Pressure boundary
Strainer (Element)	Filter
Tank (Air receiver)	Pressure boundary
Tank (Clean fuel drain)	Leakage boundary (spatial)
Tank (Dirty fuel drain)	Leakage boundary (spatial)
Tank (Dirty fuel oil drain)	Leakage boundary (spatial)
Tank (Expansion)	Pressure boundary
Tank (Fuel oil day)	Pressure boundary
Tank (Fuel oil storage)	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.8 Fire Protection System

Description

The FP program assures, through a defense-in-depth design, that a fire will not prevent the necessary safe plant shutdown functions from occurring. The protection program decreases the risk of a fire that could lead to radioactive release to the environment. The program consists of detection and extinguishing systems, administrative controls and procedures, and trained personnel. The defense-in-depth principle is aimed at achieving an adequate balance in these areas along with:

- Preventing fires from starting,
- Detecting fires quickly, rapidly suppressing fires that occur and limiting their damage, and
- Designing plant safety systems so that a fire which starts in spite of the FP program and burns for a significant period of time will not prevent essential plant safety functions from being performed.

Water supply for the FP system inside the protected area is provided by two 300,000 gallon dedicated storage tanks. The tanks are supplied by two deep wells, each with a 700 gpm makeup pump. These water supplies are strained and filtered for normal makeup.

There are three fire pumps, two diesel engine driven and one electric motor driven. Each pump is rated for 2500 gpm capacity at 125 psi. A single 70 gpm, 125 psig pressure maintaining pump (jockey pump) is provided to keep the system filled and pressurized during low flow flushing and in the event of system leakage.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The FPS boundaries are reflected on the SLRBDs listed below:

- H-11033001-SLR
- H-11033002-SLR
- H-11033003-SLR
- H-11033004-SLR
- H-11034-SLR
- H-11035-SLR
- H-11302001-SLR
- H-11302002-SLR
- H-11302003-SLR
- H-11302004-SLR
- H-11304001-SLR
- H-11304002-SLR
- H-11304003-SLR
- H-11304004-SLR
- H-11304005-SLR
- H-11304006-SLR
- H-11304007-SLR
- H-11304008-SLR
- H-11304010-SLR
- H-11319-SLR
- H-11322-SLR
- H-11323-SLR
- H-11324-SLR
- H-11325-SLR
- H-11326-SLR
- H-11374-SLR
- H-16020-SLR
- H-21016-SLR
- H-21017-SLR
- H-21186-SLR
- H-21187-SLR
- H-21188-SLR
- H-21189-SLR
- H-21190-SLR
- H-21196-SLR
- H-21197-SLR
- H-21198-SLR
- H-21199-SLR
- H-21200-SLR
- H-21201-SLR
- H-21202-SLR
- H-26053-SLR
- H-26078-SLR
- H-26372-SLR

- H-26377-SLR
- H-40133-SLR
- H-40390-SLR
- H-40391-SLR
- H-40392-SLR
- H-40393-SLR
- H-40394-SLR
- H-40395-SLR
- H-40396-SLR
- H-40397-SLR
- H-40406-SLR
- H-41508-SLR
- H-41509-SLR
- H-46532-SLR
- H-50036-SLR
- H-50041-SLR
- H-50042-SLR
- H-50043-SLR
- H-50044-SLR
- H-50045-SLR
- H-50046-SLR
- H-50047-SLR
- H-50051-SLR
- H-50276-SLR
- H-52554-SLR
- H-53475-SLR
- H-53501-SLR

The system interfaces with the PSW system at Unit 1 valves 1P41F121 and 1P41F122 shown on drawing H-11034-SLR coordinate C-5 and Unit 2 valves 2P41F108 and 2P41F109 shown on H-21017-SLR coordinate B-5.

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

FSAR References

Unit 2 Section 9.5.1

Components Subject to AMR

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

Table 3.3.2-8 provides the results of the AMR.

Table 2.3.3-8 - Fire Protection System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Expansion joint	Expansion/separation
Fire hydrant	Pressure boundary
Nozzle	Pressure boundary
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Pump casing (Electrical motor driven fire)	Pressure boundary
Pump casing (Engine driven fire)	Pressure boundary
Pump casing (Fire water jockey)	Pressure boundary
Sprinkler	Leakage boundary (spatial) Pressure boundary Spray
Strainer (Element)	Filter
Tank (Carbon dioxide storage)	Pressure boundary
Tank (FP storage)	Pressure boundary
Tank (Fuel oil)	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.9 Fuel Pool Cooling and Cleanup System

Description

The FPCC system is designed to remove the decay heat generated by the spent fuel assemblies stored in the fuel pool and maintain the pool water at a clarity and purity suitable for underwater operations and protection of personnel in the refueling area.

The FPCC system is designed to perform the following NSR functions:

- Maintain the pool water temperature < 150 °F under normal operating conditions, refueling conditions, and core offload conditions.
- Prevent overheating of the fuel assemblies by ensuring the fuel elements are completely submerged underwater.
- Maintain a minimum water level above the stored fuel assemblies to limit direct radiation as required by 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994) for areas designated as unrestricted access.
- Minimize fission product concentration in the water through purification to permit unrestricted access for plant personnel to the wet spent-fuel storage area.
- Minimize corrosion product buildup to maintain the visual clarity needed for underwater handling of fuel assemblies.

The HNP Unit 1 FPCC system consists of two pumps, two heat exchangers, and two filter-demineralizer units. The Unit 2 FPCC system contains one pump, one heat exchanger, and one filter-demineralizer unit. Each FPCC system also contains its associated valves, instruments, and piping. The two FPCC systems can be shared using an 8-inch crosstie header from the HNP Unit 1 to the HNP Unit 2 FPCC system. Interconnection of the RHR system to each unit's FPCC system is possible in the event that unloading of an abnormal amount of irradiated fuel is required. All portions of the FPCC system between the RHR system cross connection up to and including the boundary isolation valves are Seismic Category I. The remainder of the system, including the heat exchanger, pump, and filter-demineralizer, is non-seismic.

During normal operation, the FPCC system pumps take suction from the common outlet header of the spent-fuel skimmer/surge tanks and pumps the water through the heat exchanger and filter-demineralizer. From the filter-demineralizer, water is returned to the pool through two diffusers located at the bottom of the pool. The cool water traverses the spent-fuel assemblies, picking up heat and impurities before repeating the cycle by flowing over the adjustable weirs into the skimmer/surge tanks. The RBCCW system removes the heat from the fuel pool cooling heat exchanger. In the event that an abnormally large amount of irradiated fuel is unloaded or the fuel cooling train experiences a failure during refueling operations, a cooling train of the RHR system can be used for cooling the pool water. Also, the decay heat removal (DHR) system can be placed in service to provide additional cooling.

SR makeup to the fuel pool is provided by the PSW system.

<u>Boundary</u>

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The FPCC system boundaries are reflected on the SLRBDs listed below:

- H-16002-SLR
- H-16003-SLR
- H-21037001-SLR
- H-26039-SLR
- H-26040-SLR
- H-26050-SLR

The FPCC system interfaces with the RHR, radwaste, condensate transfer and storage, closed cooling water, radioactive equipment and floor drain, sampling, PSW, and RWCU systems where system changes occur.

System Intended Functions

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

(1) Contains SR piping and piping components connected to the RHR system
(2) Contains SR piping and piping components connected to the PSW system that is used for emergency makeup

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 CFR54.4(a)(3)):

None.

FSAR References

Unit 1 Section 1.12.3.3
Unit 2 Section 9.1.3

Components Subject to AMR

Table 2.3.3-9 lists the FPCC system component types that require an AMR and their associated component intended functions.

Table 3.3.2-9 provides the results of the AMR.

Table 2.3.3-9 - Fuel Pool Cooling and Cleanup System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (Fuel pool) channel head	Leakage boundary (spatial)
Heat exchanger (Fuel pool) shell	Leakage boundary (spatial)
Orifice	Leakage boundary (spatial) Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Pump casing (Fuel pool/cooling)	Leakage boundary (spatial)
Pump casing (Fuel pool holding)	Leakage boundary (spatial)

Component Type	Component Intended Function
Pump casing (Precoat)	Leakage boundary (spatial)
Tank (Fuel pool filter demineralizer)	Leakage boundary (spatial)
Tank (Fuel pool f/d precoat tank with internal coating)	Leakage boundary (spatial)
Tank (Skimmer surge)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.10 Instrument Air System

Description

The instrument air system is an auxiliary system that provides dried and filtered air to all of the air operated instruments and valves throughout the entire plant (with the exception of equipment inside the drywell as the drywell pneumatic system is responsible for supplying the motive gas for these components). The instrument air system is divided into two subsystems, the non-interruptible system which provides instrument air for the operation of certain emergency system components, and the interruptible system which provides instrument air to all other components not supplied by the non-interruptible system.

The compressed air systems are supplied by three oil-free screw-type compressors. Two of these air compressors have a capacity of 500 SCFM (standard cubic feet per minute) and one has a capacity of 700 SCFM. During normal operation, the 700 SCFM compressor supplies all instrument air and high pressure service air requirements outside of the drywell with one of the two 500 SCFM compressors on automatic standby and the other (which requires operator action for start) in the backup mode. Each compressor discharges into an air receiver which in turn discharges into a common manifold that feeds the instrument and service air systems. The service air system also provides containment isolation functions.

The compressors and related components are not required for the non-interruptible system. The air volume in the air accumulators and associated piping is sufficient to provide the air supply for components that require non-interruptible air.

Boundary

The boundary of the instrument air system is shown on the SLRBDs listed below:

- H-16011-SLR
- H-16013-SLR
- H-16020-SLR
- H-16024-SLR
- H-16037-SLR
- H-16062-SLR
- H-16174-SLR
- H-16239001-SLR
- H-16239002-SLR
- H-16239004-SLR
- H-16239005-SLR

- H-16239006-SLR
- H-16239007-SLR
- H-16276-SLR
- H-16329-SLR
- H-16330-SLR
- H-16331-SLR
- H-16332-SLR
- H-16334-SLR
- H-26000-SLR
- H-26014-SLR
- H-26015-SLR
- H-26018-SLR
- H-26023-SLR
- H-26048-SLR
- H-26050-SLR
- H-26051-SLR
- H-26058-SLR
- H-26064-SLR
- H-26070-SLR
- H-26078-SLR
- H-26084-SLR
- H-26086-SLR

The instrument air system interfaces with various systems that have air operated components. The air operated components themselves are included in their native system while the air supplies to those components are included in the instrument air system.

System Intended Functions

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

(1) The instrument air system provides non-interruptible essential instrument air supply to certain emergency systems.
(2) The instrument air system maintains containment pressure boundary integrity at the containment penetrations including containment isolation.

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, and SBO.

FSAR References

Unit 1 Section 10.11
Unit 2 Section 9.3.1

Components Subject to AMR

Table 2.3.3-10 lists the instrument air 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 - Instrument Air System Components Subject to Aging Management Review

Component Type	Component Intended Function
Accumulator (Air receiver)	Pressure boundary
Bolting (Closure)	Mechanical closure
Hose	Pressure boundary
Piping and piping components	Pressure boundary
Pressure regulator	Pressure boundary
Valve body	Pressure boundary

2.3.3.11 Non-Safety Affecting Safety Systems

Description

The non-safety affecting safety systems are fluid-filled systems located near SR components in the reactor building, intake structure, or certain control building areas. These systems do not perform a LR intended function in accordance with 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3) but have the potential to leak or spray on SR components that are in scope in accordance with 10 CFR 54.4(a)(2).

The non-safety affecting safety systems comprise the following:

Control building chilled water system
Control building domestic water system
Control building equipment, floor drain system (radioactive)
Control building sanitary drain system
DHR system
Electro-hydraulic control (EHC) system
Lube oil system
Other buildings, domestic water
Plant heating system
Radioactive equipment and floor drain system
Reactor building and RWB chilled water system

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The non-safety affecting safety systems boundaries are reflected on the SLRBDs listed below:

- D-11001-SLR
- D-11004-SLR
- D-11006-SLR
- H-11029-SLR
- H-11636-SLR
- H-11734-SLR
- H-16015-SLR
- H-16018-SLR
- H-16039-SLR
- H-16176-SLR
- H-16266-SLR
- H-16329-SLR
- H-16330-SLR
- H-21033-SLR
- H-21039-SLR
- H-21051-SLR
- H-21063-SLR
- H-26008-SLR
- H-26020-SLR
- H-26023-SLR
- H-26025-SLR
- H-26065-SLR
- H-26075-SLR
- H-26080-SLR
- H-26384-SLR
- H-44131-SLR
- H-44132-SLR
- H-44753-SLR
- H-50563-SLR
- H-51178-SLR
- H-51179-SLR
- H-52124-SLR
- S-11172-SLR
- S-21023-SLR

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))

None.

FSAR References

Unit 1 Sections 7.11, 8.4.3, and 10.13
Unit 2 Sections 9.1.3, 9.3.3.2, 9.3.8.2, 9.4.7.2.12, 10.2.2, and 14A.38

Components Subject to AMR

Table 2.3.3-11 lists the non-safety affecting safety systems 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 - Non-Safety Affecting Safety Systems Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (closure)	Mechanical closure
Drain pan	Leakage boundary (spatial)
Fan housing (Vapor extractor)	Leakage boundary (spatial)
Filter housing (Fuller's earth)	Leakage boundary (spatial)
Filter housing (PD pump suction)	Leakage boundary (spatial)
Heat exchanger (Chillers) shell	Leakage boundary (spatial)
Heat exchanger (Condenser) shell	Leakage boundary (spatial)
Heat exchanger (Decay heat removal) shell	Leakage boundary (spatial)
Heat exchanger (EHC fluid cooler) shell	Leakage boundary (spatial)
Heat exchanger (Evaporator) shell	Leakage boundary (spatial)
Heat exchanger (Hot water) shell	Leakage boundary (spatial)
Heat exchanger (Lube oil cooler) shell	Leakage boundary (spatial)
Heat exchanger (Oil cooler) shell	Leakage boundary (spatial)
Hose	Leakage boundary (spatial)
Orifice	Leakage boundary (spatial)
Piping and piping components	Leakage boundary (spatial)
Pump casing (Chilled water)	Leakage boundary (spatial)
Pump casing (Condenser circulating water)	Leakage boundary (spatial)
Pump casing (Control building equipment drain sump)	Leakage boundary (spatial)
Pump casing (Control building floor drain sump)	Leakage boundary (spatial)
Pump casing (Control building non-radioactive sump)	Leakage boundary (spatial)
Pump casing (DHR primary side)	Leakage boundary (spatial)
Pump casing (EHC PD)	Leakage boundary (spatial)

Component Type	Component Intended Function
Pump casing (Hot water circulation)	Leakage boundary (spatial)
Pump casing (Hot water system chemical addition)	Leakage boundary (spatial)
Pump casing (Lube oil condenser vapor extractor)	Leakage boundary (spatial)
Pump casing (Lube oil transfer)	Leakage boundary (spatial)
Pump casing (Main turbine lube oil vapor extractor)	Leakage boundary (spatial)
Pump casing (Primary hot water recirculation)	Leakage boundary (spatial)
Pump casing (Radwaste and radwaste addition building hot water circulating)	Leakage boundary (spatial)
Pump casing (Reactor building hot water secondary recirculating)	Leakage boundary (spatial)
Pump casing (Sewage ejector 1A&1B)	Leakage boundary (spatial)
Pump casing (Turbine lube oil storage transfer)	Leakage boundary (spatial)
Pump casing (Turbine oil transfer)	Leakage boundary (spatial)
Pump casing (Turbine and control building hot water secondary recirculating)	Leakage boundary (spatial)
Rupture disc	Leakage boundary (spatial)
Sight glass	Leakage boundary (spatial)
Tank (Air dryer)	Leakage boundary (spatial)
Tank (Air separator)	Leakage boundary (spatial)
Tank (Collection tank)	Leakage boundary (spatial)
Tank (EHC oil reservoir)	Leakage boundary (spatial)
Tank (Expansion tank)	Leakage boundary (spatial)
Tank (Hot water system air separator)	Leakage boundary (spatial)
Tank (Hot water system chemical addition)	Leakage boundary (spatial)
Tank (Hot water system expansion)	Leakage boundary (spatial)
Tank (Main turbine oil conditioner)	Leakage boundary (spatial)
Tank (Oil storage)	Leakage boundary (spatial)
Tank (Refueling floor vent drain pots)	Leakage boundary (spatial)
Tank (Turbine oil reservoir)	Leakage boundary (spatial)
Tank (Water heater)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial)

2.3.3.12 Primary Containment Chilled Water System (Unit 2 Only)

Description

The Unit 2 PCCW system consists of two redundant chilled water recirculation pumps, two redundant centrifugal chillers, and several fan coil units. Each chiller consists of a refrigerant compressor, condenser, cooler, accessories, and controls. Each chilled water recirculation pump circulates chilled water through its respective chiller and fan coil units. The PCCW components inside of containment form a closed loop that is credited for meeting 10 CFR 50 Appendix A, General Design Criterion (GDC) 57 for closed systems within primary containment. The PCCW system does not have any other SR functions but portions of the PCCW system are in scope due to the potential to leak or spray on SR components.

The Unit 1 drywell cooling system does not utilize a separate chilled water system because it utilizes the PSW system for heat removal.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The boundaries of the PCCW system are shown on the SLRBDs listed below:

- H-26008-SLR
- H-26080-SLR
- H-26081-SLR

The PCCW system interfaces with the non-safety affecting safety systems at Unit 2 valves 2P65F137, 2P65F138, and 2P65F140 shown on drawing H-26008-SLR coordinate E-10.

The PCCW system interfaces with the PSW system at the Unit 2 condensers shown on drawing H-26080 coordinates B-3 and H-3.

System Intended Functions

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

(1) The PCCW system maintains containment pressure boundary integrity at the containment penetrations including containment isolation.

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.

FSAR References

Unit 2 Section 9.4.6.2.2

Components Subject to AMR

Table 2.3.3-12 lists the PCCW system (Unit 2 only) component types that require an AMR and their associated component intended functions.

Table 3.3.2-12 provides the results of the AMR.

Table 2.3.3-12 - Primary Containment Chilled Water System (Unit 2 Only) Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (Condenser) shell	Leakage boundary (spatial)
Heat exchanger (Evaporator) shell	Leakage boundary (spatial)
Heat exchanger (Condenser) channel head	Leakage boundary (spatial)
Heat exchanger (Evaporator) channel head	Leakage boundary (spatial)
Heat exchanger (Primary containment cooling units) return bends	Pressure boundary
Heat exchanger (Primary containment cooling units) tubes	Pressure boundary
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping elements	Leakage boundary (spatial)
Pump casing (Chemical feed)	Leakage boundary (spatial)
Pump casing (Chilled water)	Leakage boundary (spatial)
Tank (Chemical addition tank)	Leakage boundary (spatial)
Tank (Expansion tank)	Leakage boundary (spatial)
Thermowell	Leakage boundary (spatial) Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.13 Process Radiation Monitoring System

Description

The process radiation monitoring (PRM) system furnishes information to operations personnel regarding radioactivity levels in principal plant process and effluent streams to assist in maintaining radiation levels as low as reasonably achievable (ALARA) and to verify compliance with applicable governmental regulations for the containment, control, and release of radioactive liquids, gases, and particulates generated as a result of normal or emergency operations of the plant. The PRM system contains both instruments that are connected to other systems and standalone instruments that measure area radiation.

The PRM system is designed to measure and record radioactivity levels, to alarm on high radioactivity levels, and to control, as required, the release of radioactive liquids, gases, and particulates produced in the operation of the plant.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The portion of the system that is highlighted on the boundary drawings are only in scope for containment isolation. The PRM system boundaries are reflected on the SLRBDs listed below:

- H-16173-SLR
- H-26016-SLR

System Intended Functions

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

(1) The PRM system is designed to measure and record radioactivity levels, to alarm on high radioactivity levels, and to control, as required, the release of radioactive liquids, gases, and particulates produced in the operation of the plant.
(2) Portions of the PRM are connected to, and part of, the reactor coolant pressure boundary during plant operation.
(3) The PRM system maintains containment pressure boundary integrity at the containment penetrations including containment isolation.

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 EQ.

FSAR References

Unit 1 Section 7.12
Unit 2 Section 11.4

Components Subject to AMR

Table 2.3.3-13 lists the PRM 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 - Process Radiation Monitoring System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Hose	Pressure boundary
Piping and piping components	Pressure boundary
Valve body	Pressure boundary

2.3.3.14 Radwaste System

Description

The radwaste system is a normally operating system designed to collect, process, and dispose of potentially radioactive wastes produced during the operation of the plant. The radwaste system consists of gaseous, liquid, and solid radwaste plant systems. The portions of the radwaste system that are in-scope for SLR are those components in the liquid radwaste system that support the primary containment boundary and those that provide a leakage boundary to preclude system interactions with SR components.

Gaseous Radwaste System
The purpose of the gaseous radwaste system is to process and control the release of gaseous radioactive wastes to the site environs so that the total radiation exposure to individuals outside the controlled area is ALARA and does not exceed the design objectives in 10 CFR 50, Appendix I.

Liquid Radwaste System
The liquid radwaste system is designed to process and recycle the liquid waste collected in the waste holdup tank to the extent practicable. Liquid waste collected in chemical or floor drain tanks is normally discharged to the environment after treatment and dilution. During normal plant operations, the annual radiation doses to individuals from each reactor on the site, resulting from these routine liquid waste discharges, are within the 10 CFR 50, Appendix I, design objectives. Short-term releases from the plant resulting from equipment malfunctions or operational transients are within the limits specified in the radioactive effluent controls program.

Solid Radwaste System
The solid radwaste system collects, monitors, processes, packages, and provides temporary storage facilities for radioactive solid wastes for off-site shipment and permanent disposal. The wet solid radwaste system is a continuous part of the liquid radwaste system. The wet solids, consisting of spent demineralizer bead resins and powdered filter resins, are pumped in slurry form to the resin dewatering and packaging system for offsite shipment. Dry solid radwaste such as air filters, miscellaneous paper, rags, and tools is accumulated at designated storage areas for processing and disposal.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The radwaste system boundaries are reflected on the SLRBDs listed below:

- H-16009-SLR
- H-16016-SLR
- H-16176-SLR
- H-16177-SLR
- H-16179-SLR
- H-16189-SLR
- H-26014-SLR
- H-26026-SLR
- H-2602702-SLR
- H-26055-SLR

The radwaste system interfaces with the miscellaneous auxiliary systems by collecting water from various drain lines in the reactor building shown on SLRBDs H-16176-SLR and H-26026-SLR.

System Intended Functions

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

(1) The radwaste system maintains containment pressure boundary integrity at the containment penetrations including containment isolation.

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 and EQ.

FSAR References

Unit 1 Section 9.1, 9.2, 9.3, and 9.4
Unit 2 Section 11.2, 11.3, and 11.5

Components Subject to AMR

Table 2.3.3-14 lists the radwaste 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 - Radwaste System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (Drain sump) channel head with internal coating	Leakage boundary (spatial)
Heat exchanger (Drain sump) shell	Leakage boundary (spatial)
Orifice	Leakage boundary (spatial)
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Pump casing (Cleanup decant)	Leakage boundary (spatial)
Pump casing (Cleanup sludge discharge mix)	Leakage boundary (spatial)
Pump casing (Reactor building equipment drain)	Leakage boundary (spatial)
Pump casing (Reactor building floor drain)	Leakage boundary (spatial)
Tank (Cation floc & measuring)	Leakage boundary (spatial)
Tank (Cleanup phase separators)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.15 Reactor Building Closed Cooling Water System

Description

The RBCCW system is a closed-loop cooling system consisting of three one-half capacity pumps, two full-capacity heat exchangers, a surge tank, and a chemical addition system. The cooling water is conveyed by the pumps to the various system coolers and returned to the pumps by way of the RBCCW heat exchangers. Two of the one-half capacity RBCCW pumps are required to support reactor operations with the third pump on standby. The system is started manually. The standby pump, when needed, starts automatically. The heat rejected by the RBCCW system to the heat exchangers is removed by the PSW system. To prevent the release of chemically treated water to the environment, the PSW at the heat exchangers is maintained at a higher pressure than the RBCCW side. The RBCCW components inside of containment form a closed loop that is credited for meeting 10 CFR 50 Appendix A, GDC 57 for closed systems within primary containment. The RBCCW system does not have any other SR functions but portions of the RBCCW system are in scope due to the potential to leak or spray on SR components.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The RBCCW system boundaries are reflected on the SLRBDs listed below:

- H-16009-SLR

- H-16066-SLR
- H-16286-SLR
- H-26003-SLR
- H-26054-SLR
- H-26055-SLR
- H-26066-SLR

The RBCCW system interfaces with the sampling system at Unit 1 valve 1P42F072 shown on drawing H-16009-SLR coordinate B-9 and Unit 2 valve 2P42F072 shown on drawing H-26055-SLR coordinate A-3.

The RBCCW system interfaces with the demineralized water supply system at Unit 1 valves 1P42F055, 1P42F027, and 1P42F028 shown on drawing H-16009-SLR coordinates C-4, D-4, and D-3. The RBCCW system interfaces with the demineralized water supply system at Unit 2 valves 2P42F055, 2P42F027, and 2P42F028 shown on drawing H-26054-SLR coordinates A-9, A-10, and A-11.

The RBCCW system interfaces with the radwaste system at Unit 1 valves 1P42F067A&B shown on drawing H-16009-SLR coordinate E-1 and Unit 2 valves 2P42F067A&B shown on drawing H-26055-SLR coordinate A-3.

The RBCCW system interfaces with the radwaste, reactor recirculation, CRD, RWCU, FPCC, and sampling systems at various heat exchangers and coolers shown on drawings H-16009-SLR and H-26055-SLR.

The RBCCW system interfaces with the drywell pneumatic system at the compressors and after coolers shown on drawings H-16286-SLR and H-26066-SLR.

System Intended Functions

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

(1) The RBCCW system maintains containment pressure boundary integrity at the containment penetrations including containment isolation.

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 and SBO.

FSAR References

Unit 1 Section 10.5
Unit 2 Section 9.2.2

Components Subject to AMR

Table 2.3.3-15 lists the RBCCW system component types that require an AMR and their associated component intended functions.

Table 3.3.2-15 provides the results of the AMR.

Table 2.3.3-15 - Reactor Building Closed Cooling Water System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Compressor housing (Drywell pneumatic)	Leakage boundary (spatial)
Heat exchanger (Drywell pneumatic after cooler) shell	Leakage boundary (spatial)
Heat exchanger (Drywell sump cooler) shell	Pressure boundary
Hose	Pressure boundary
Orifice	Leakage boundary (spatial) Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Pump casing (RBCCW chem add)	Leakage boundary (spatial)
Tank (RBCCW chem add)	Leakage boundary (spatial)
Tank (RBCCW surge)	Leakage boundary (spatial)
Thermowell	Leakage boundary (spatial) Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.16 Reactor Building HVAC System

Description

The purposes of the reactor building HVAC system are to:

- Provide an environment with controlled temperature and airflow to ensure the comfort and safety of operating personnel and to optimize equipment performance by the removal of the heat dissipated from the plant equipment
- Promote air movement from operating areas and areas of lower airborne radioactivity potential to areas of greater airborne radioactivity potential prior to final filtration and exhaust
- Minimize the release of potential airborne radioactivity to the environment during normal plant operation by exhausting air, through a filtration system, from the areas in which a significant potential for radioactive particulates or radioiodine contamination

exists
- Provide a source of cooling to support the operation of the ECCS
- Provide isolation capability to maintain secondary containment integrity and support operation of the SBGT system

The reactor building HVAC system utilizes a combination of air conditioning, heating, and once-through ventilation. Heating is provided by hot water heating coils which are served by the plant heating system. Heat removal is provided by the cooled ventilation air. The ventilation air for the SR coolers is cooled by the PSW system. The NSR coolers are cooled by the reactor building chilled water system and the hot water coils are heated by the plant heating system.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The reactor building HVAC system boundaries are reflected on the SLRBDs listed below:

- H-16005-SLR
- H-16011-SLR
- H-16014-SLR
- H-16020-SLR
- H-16023-SLR
- H-26051-SLR
- H-26067-SLR
- H-26071-SLR
- H-26072-SLR

System Intended Functions

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

(1) The reactor building HVAC system maintains temperature limits within areas containing SR components. The system provides ventilation to the ECCS rooms to maintain the equipment temperatures below the limits that are required for safe shutdown of the plant.
(2) Portions of the secondary containment boundary are provided by the reactor building HVAC system, which includes SR secondary containment isolation dampers.

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.

FSAR References

Unit 1 Sections 10.9.2, 10.9.3.2, and 10.9.3.3
Unit 2 Sections 9.4.2.1.2, 9.4.2.2, and 9.4.2.3

Components Subject to AMR

Table 2.3.3-16 lists the reactor building HVAC 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 - Reactor Building HVAC System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Bolting (HVAC closure)	Mechanical closure
Drip pan	Leakage boundary (spatial)
Ducting and ducting components	Pressure boundary
Fan housing	Pressure boundary
Heat exchanger (Core spray and RHR pump room cooler) channel head	Pressure boundary
Heat exchanger (Core spray and RHR pump room cooler) fins	Heat transfer
Heat exchanger (Core spray and RHR pump room cooler) tubes	Heat transfer Pressure boundary
Heat exchanger (CRD pump room cooler) channel head	Pressure boundary
Heat exchanger (CRD pump room cooler) fins	Heat transfer
Heat exchanger (CRD pump room cooler) tubes	Heat transfer Pressure boundary
Heat exchanger (Hot water coils) tubes	Leakage boundary (spatial)
Heat exchanger (HPCI room cooler) channel head	Pressure boundary
Heat exchanger (HPCI room cooler) fins	Heat transfer
Heat exchanger (HPCI room cooler) tubes	Heat transfer Pressure boundary
Heat exchanger (NSR coolers) tubes	Leakage boundary (spatial)
Heat exchanger (RCIC pump room cooler) channel head	Pressure boundary
Heat exchanger (RCIC pump room cooler) fins	Heat transfer

Component Type	Component Intended Function
Heat exchanger (RCIC pump room cooler) tubes	Heat transfer Pressure boundary
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.17 Reactor Water Cleanup System

Description

The purpose of the RWCU system is to maintain high reactor water purity to limit chemical and corrosive action, thereby limiting fouling and deposition on heat transfer surfaces. The RWCU system also removes corrosion products to limit impurities available for neutron activation and resultant radiation from deposition of corrosion products.

The major equipment of the RWCU system is located in the reactor building. It consists of pumps, regenerative and non-regenerative heat exchangers, and two filter-demineralizers with supporting equipment. The entire system is connected by associated valves and piping; controls and instrumentation provide proper system operation.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The RWCU system boundaries are reflected on the SLRBDs listed below:

- H-11511-SLR
- H-16009-SLR
- H-16063-SLR
- H-16065-SLR
- H-16188-SLR
- H-16189-SLR
- H-16281-SLR
- H-26027-SLR
- H-26036-SLR

The RWCU system interfaces with the nuclear boiler system at valve 1G31F004 on drawing H-16188-SLR coordinate C-3 and at valve 2G31F004 on drawing H-26036-SLR coordinate C-3.

The RWCU system interfaces with the RCIC system at valve 1G31F039 on drawing H-16188-SLR coordinate A-4 and at valve 2G31F039 on drawing H-26036-SLR coordinate B-4.

The RWCU system interfaces with the HPCI system at valve 1G31F203 on drawing H-16188-SLR coordinate B-4 and at valve 2G31F144 on drawing H-26036-SLR coordinate B-4.

System Intended Functions

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

(1) Provides SR boundary valves to other SR 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 EQ and FP.

FSAR References

Unit 1 Section 4.9
Unit 2 Sections 5.2.1.1.8 and 7.6.6

Components Subject to AMR

Table 2.3.3-17 lists the RWCU system component types that require an AMR and their associated component intended functions.

Table 3.3.2-17 provides the results of the AMR.

Table 2.3.3-17 - Reactor Water Cleanup System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (RWCU non-regenerative) channel head	Leakage boundary (spatial)
Heat exchanger (RWCU non-regenerative) shell	Leakage boundary (spatial)
Heat exchanger (RWCU pump cooler) channel head	Leakage boundary (spatial)
Heat exchanger (RWCU pump cooler) shell	Leakage boundary (spatial)
Heat exchanger (RWCU regenerative) channel head	Leakage boundary (spatial)
Heat exchanger (RWCU regenerative) shell	Leakage boundary (spatial)
Orifice	Leakage boundary (spatial)
Piping and piping components	Leakage boundary (spatial)
Pump casing (Cleanup recirc)	Leakage boundary (spatial)
Pump casing (Holding)	Leakage boundary (spatial)
Pump casing (Precoat)	Leakage boundary (spatial)

Component Type	Component Intended Function
Tank (Filter demineralizer) with internal coating	Leakage boundary (spatial)
Tank (RWCU precoat) with internal coating	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.18 Sampling System

Description

The sampling system consists of process sampling systems, the hydrogen (H_2) and oxygen (O_2) analyzer system, the post accident sampling system (PASS), and the turbine water analysis system.

The process sampling systems are designed to obtain representative samples in forms which can be used in radiochemical laboratory analyses for determination of plant equipment effectiveness. The systems are designed to minimize the radiation effects at the sampling stations.

The primary containment hydrogen and oxygen analyzing system consists of two separate, redundant systems, each capable of analyzing the hydrogen and oxygen content from the drywell or torus. Each analyzer channel is operated in parallel from separate penetrations in the drywell and torus. The sample is drawn through a sample cooler by the sample system inlet pump, then pumped to the hydrogen and oxygen analyzer cells. The sample is then returned to the primary containment by the sample system outlet pump.

The PASS is designed to take samples from both the HNP Unit 1 and HNP Unit 2 reactor and drywell atmospheres. Appropriate valving is provided such that the reactor coolant and containment atmosphere samples can be obtained from either unit at one location, the post-accident sampling room.

The turbine water analysis system does not include SR components nor any components which are located in an area where spatial interaction with SR SSCs may occur. Therefore, the turbine water analysis system is not within the scope of SLR.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The sampling system boundaries are reflected on the SLRBDs listed below:

- H-16009-SLR
- H-16011-SLR
- H-16015-SLR
- H-16024-SLR
- H-16063-SLR
- H-16173-SLR
- H-16276-SLR
- H-16281-SLR

- H-26003-SLR
- H-26016-SLR
- H-26036-SLR
- H-26038-SLR
- H-26047-SLR
- H-26048-SLR
- H-26049-SLR
- H-26055-SLR
- H-26384-SLR

The post accident sampling room does not contain SR equipment and is physically separated from the rest of the reactor building; therefore, the leakage boundary for the PASS is terminated at the penetration into the post accident sampling room.

The sample panels shown on drawings H-16281-SLR and H-26038-SLR provide a spray shield around the NSR, fluid-filled components housed within; therefore, the leakage boundary for associated sampling lines is terminated at the penetration into the sample panel enclosure.

The sampling system interfaces with the primary containment purge and inerting system at a sample point connection on the vent purge outlet line extending from the drywell to a sample point connection from another line extending from the torus as shown on drawing H-16024-SLR coordinates C-5 and G-9, respectively. Additionally, the sampling system interfaces with the primary containment purge and inerting system at valve P33F120B shown on drawing H-16276-SLR coordinate B-3.

The sampling system interfaces with the primary containment (torus and drywell) at penetrations X-28F, X-34E, X-31D, and X-217 shown on drawing H-16276-SLR coordinates C-2, D-2, E-2, and H-3.

The sampling system interfaces with the demineralized water system at valve P33F231 shown on drawing H-16015-SLR coordinate D-10.

The sampling system interfaces with the nuclear boiler system at a sample point connection on the low pressure connection from the jet pumps shown on drawing H-16063-SLR coordinate G-5.

The sampling system interfaces with the RWCU system at valve 2G31F020 shown on drawing H-26036-SLR coordinate F-9.

The sampling system interfaces with the demineralized water system at valves P21F220 and P21F054 shown on drawing H-26047-SLR coordinates D-8 and F-9.

The sampling system interfaces with the primary containment (torus and drywell) at penetrations X-3, X-60A, X-28, X-64, X-217A, and X-217B shown on drawing H-26048-SLR coordinates B-2, C-2, D-2, E-2, and H-3.

The sampling systems interfaces with the nuclear boiler system at sample point connections from low and high pressure connections from the jet pumps shown on drawing H-26384-SLR coordinates E-2 and E-11.

The sampling system interfaces with the HPCI system at two return line connections shown on drawing H-26384-SLR coordinates J-3 and J-9.

System Intended Functions

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

(1) The H_2O_2 analyzer system provides a primary containment isolation function.
(2) Portions of the PASS are required to maintain the reactor coolant pressure boundary.

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 regulation for EQ.

FSAR References

Unit 1 Section 10.14
Unit 2 Section 7.6.11 and 9.3.2

Components Subject to AMR

Table 2.3.3-18 lists the sampling system component types that require an AMR and their associated component intended functions.

Table 3.3.2-18 provides the results of the AMR.

Table 2.3.3-18 - Sampling System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (Sample cooler) shell	Leakage boundary (spatial)
Heat exchanger (H_2O_2 analyzer) tubes	Pressure boundary
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Pump casing (H_2O_2 analyzer)	Pressure boundary
Tank (Moisture separator)	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.19 Plant Service Water System

Description

The PSW system removes the heat generated by the operation of various systems (both SR and NSR). The PSW system also provides makeup water to the plant circulating water system. After traveling through the various system heat exchangers, the water is routed to the circulating water flume for use as flume makeup. The heat picked up by the water is rejected to the atmosphere via the plant cooling towers or to the river via the circulating water flume overflow. The PSW system water is also available for fire-fighting, radwaste dilution, and emergency SFP makeup.

The PSW system consists of four main pumps divided into two divisions of two pumps each. Each of the two divisions supplies one redundant train of SR equipment. After passing through isolation valves, the two SR headers merge into one header supplying NSR equipment. After servicing the various systems, the service water is discharged to a potential radioactive contaminant release path, and the discharge header is constantly monitored for activity.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The PSW system boundaries are reflected on the SLRBDs listed below:

- D-11001-SLR
- D-11004-SLR
- H-11024-SLR
- H-11600-SLR
- H-11609-SLR
- H-16002-SLR
- H-16011-SLR
- H-16329-SLR
- H-16330-SLR
- H-21033-SLR
- H-21035-SLR
- H-21039-SLR
- H-26050-SLR
- H-26051-SLR
- H-26053-SLR

The PSW system interfaces with the screen wash system at Unit 1 valves 1P41F1500A and 1P41F1500B shown on drawing D-11001-SLR coordinates B-4 and C-5, respectively. The PSW system also interfaces with the screen wash system at Unit 2 valves 2P41F1500A and 2P41F1500B shown on drawing H-21033-SLR coordinates C-7 and F-5, respectively.

The PSW system interfaces with the RHR system at Unit 1 valves 1E11F928A&B and 1E11F930A&B shown on drawings H-16330-SLR and H-16329-SLR coordinates G-3 and H-9. The PSW system also interfaces with the RHR system at Unit 2 valves 2P41F905A&B and 2P41F907A&B shown on drawing H-21039-SLR coordinate E-8. The PSW system also interfaces with the RHR system at the flexible connections immediately upstream and downstream of the RHRSW pump motor coolers shown on drawings D-11004-SLR and H-

21039-SLR.

The PSW system interfaces with the FP system at Unit 1 valves 1P41F121 and 1P41F122 shown on drawing H-16011-SLR coordinate H-10 and F-10, respectively. The PSW system also interfaces with the FP system at Unit 2 valves 2P41F108 and 2P41F109 shown on drawing H-26051-SLR coordinate C-11 and drawing H-26050-SLR coordinate E-11, respectively.

The PSW system interfaces with the FPCC system at Unit 1 valve 1G41F217 shown on drawing H-16002-SLR coordinate C-8 and Unit 2 valve 2G41F040 shown on drawing H-26050-SLR coordinate G-8.

The PSW system interfaces with the sampling system at Unit 1 valves 1P41F104, 1P41F105, 1P41F111, and 1P41F113 shown on drawing H-16011-SLR coordinate J-3, F-3, C-10, and E-6 respectively.

The PSW system interfaces with the CAC, reactor building HVAC, and RHR systems at various coolers shown on drawing H-16011-SLR.

The PSW system interfaces with the PCCW, reactor building HVAC, control building HVAC, and RHR systems at various coolers shown on drawings H-26050-SLR and H-26051-SLR.

The PSW system interfaces with the primary containment purge and inerting system at Unit 1 valve 1P41F108 shown on drawing H-16011-SLR coordinate F-9.

The PSW system interfaces with the condensate transfer and storage system at Unit 1 valve 1P41F041 shown on drawing H-16002-SLR coordinate C-9.

The PSW system interfaces with the control building HVAC system at the A, B, and C train air conditioning units shown on drawing H-11609-SLR.

System Intended Functions

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

(1) The PSW system removes heat generated by the operation of various SR systems.
(2) Provides emergency makeup for the SFPs.

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 EQ.

FSAR References

Unit 1 Section 10.7
Unit 2 Sections 1.2.7.18, 1.2.10.2, 7.6.12, and 9.2.1

Components Subject to AMR

Table 2.3.3-19 lists the PSW component types that require an AMR and their associated component intended functions.

Table 3.3.2-19 provides the results of the AMR.

Table 2.3.3-19 - Plant Service Water System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Hose	Pressure boundary
Orifice	Pressure boundary Throttle
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Piping elements	Pressure boundary
Pump casing (PSW)	Pressure boundary
Pump casing (Standby Diesel PSW)	Pressure boundary
Strainer (element)	Filter
Thermowell	Pressure boundary
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.20 Torus Water Cleanup System

Description

The TWC system provides the capability for the cleanup of torus waters through a process of filtration and demineralization. The TWC system can also be used for reducing or completely draining the torus waters to allow inspection of the torus interior surface coating.

The TWC system consists of piping, valves, and a centrifugal pump to allow transferring of torus water to the CST, the main condenser hot well, or to the radwaste system storage tanks. Discharge to the CST or the main condenser hot well is via the condensate polishing subsystem of the condensate and feedwater system for removal of suspended and ionic impurities. Makeup to the torus is provided by gravity drain from the CST.

The TWC system is used during plant shutdown for torus drainage and purification by discharging torus water to the CST and main condenser hotwell via the condensate polishing system for removal of suspended and ionic impurities. The system can also provide torus purification and cleanup of torus water during plant operation. A spool piece is removed and two manual isolation valves located adjacent to the torus are locked closed to ensure containment integrity and to ensure that torus water level cannot be inadvertently raised or lowered through system operation or leakage. Portions of the TWC system perform the SR function to provide containment isolation. With the exception of the containment isolation function, the TWC system is NSR.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The TWC system boundaries are reflected on the SLRBDs listed below:

- H-16009-SLR
- H-16135-SLR
- H-26042-SLR
- H-26055-SLR

The TWC system interfaces with equipment drains, primary containment, radwaste, and CS systems where system changes occur.

System Intended Functions

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

(1) Provide containment isolation for fission product retention.

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.

FSAR References

Unit 2 Sections 1.2.10.5 and 9.3.7

Components Subject to AMR

Table 2.3.3-20 lists the TWC System component types that require an AMR and their associated component intended functions.

Table 3.3.2-20 provides the results of the AMR.

Table 2.3.3-20 - Torus Water Cleanup System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Piping and piping components	Leakage boundary (spatial) Pressure boundary
Pump casing (Torus drainage and purification)	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.3.21 Outside Structures HVAC System

Description

The outside structures HVAC system includes the intake structure HVAC system and the DG building HVAC system. The purpose of the outside structures HVAC system is to protect the equipment within the intake structure and DG building from adverse temperature conditions that could affect the reliability of the equipment.

The intake structure HVAC system consists of three 50 percent capacity roof-mounted exhaust ventilators, four gravity-operated louvers, and six wall-mounted unit heaters. The ventilators are powered from separate power sources. Each ventilator has a separate control station and is operated by an individual thermostat. The independent controls are powered from the motor control center (MCC) control transformer for the associated fan. Since selected PSW pumps operate during normal and accident conditions in the plant, the three thermostats and the individual fan control stations are located in the Unit 1 and Unit 2 PSW pump bay areas. The locations of the thermostats ensure the ventilation system is always activated when operation of the PSW pumps causes a heat buildup in the area. The six unit heaters and their associated thermostats are strategically located at different areas of the building to provide adequate area coverage for maintaining the building above freezing temperatures.

The DG building HVAC system consists of one power roof exhaust ventilator in each room for exhausting heat from the rooms when the generator is shut down and two 100 percent capacity power roof exhaust ventilators in each room for exhausting heat from the rooms during generator actuation. Two motor-operated wall air intake louvers along with fire dampers in each room replenish the air removed by the exhaust ventilation. One louver serves as the air intake to the generator area; the other serves as the air intake to the battery rooms through the generator area.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&ID and component system designations. The outside structures HVAC system boundaries are reflected on the SLRBD listed below:

- H-44073-SLR

System Intended Functions

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

(1) Provide heating and cooling to protect the equipment within the intake structure and DG building from adverse temperature conditions that could affect the reliability of the equipment during all operations.

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

None.

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 SBO.

FSAR References

Unit 2 Sections 9.4.5 and 9.4.10

Components Subject to AMR

Table 2.3.3-21 lists the outside structures HVAC system component types that require an AMR and their associated component intended functions.

Table 3.3.2-21 provides the results of the AMR.

Table 2.3.3-21 - Outside Structures HVAC System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (HVAC closure)	Mechanical closure
Ducting and ducting components	Pressure boundary
Fan housing	Pressure boundary
Heater housing	Pressure boundary

2.3.4 Steam and Power Conversion Systems

2.3.4.1 Condensate and Feedwater System

Description

The condensate and feedwater system is a power generation system designed to:

- Provide feedwater at the required flow and pressure to the reactor, allowing sufficient margin to provide continued flow under anticipated operational occurrences (AOOs);
- Provide feedwater at the required temperatures to the reactor with five stage (Unit 1) or six stage (Unit 2) closed feedwater heating; and
- Maintain high feedwater quality and minimize corrosion product input to the reactor.

The condensate and feedwater system consists of vertical condensate pumps that pump condensate from the condenser hotwells through the air ejector condensers, the gland-seal condenser, the condensate demineralizer and the off-gas condenser (Unit 2 only). Horizontal condensate booster pumps then pump the condensate to the suction of the reactor feed pumps through two parallel streams of four (Unit 1) or five (Unit 2) low-pressure heaters. The reactor feed pumps then pump the feedwater through two parallel streams, each with one high-pressure heater. Following the high-pressure heaters, the Unit 1 feedwater remains in 2 parallel lines and is pumped to the reactor vessel. For Unit 2, the feedwater combines into one line, then re-separates into two parallel lines and is pumped to the RPV. This allows for improved mixing and even temperature distribution of the feedwater.

The condensate and feedwater system in scope components are limited to those located in the reactor building as well as components that serve the holdup and plateout function in the turbine building. The portion of the feedwater system from Unit 1 valves 1B21F032A and 1B21F032B and from Unit 2 valves 2B21F076A and 2B21F076B to the respective RPVs is part of the nuclear boiler system.

The condensate and feedwater system includes the main condenser and low pressure turbine exhaust hood which:

- Provide a heat sink for turbine exhaust steam, turbine bypass steam, and other flows such as cascading heater drains, air ejector condenser drains, exhaust from the feed pump turbines, gland seal condenser, feedwater heater shell operating vents, and condensate pump suction vents;
- Deaerate the condensate, provide feedwater of required quality, and provide for removal of non-condensible gases from the condensing steam and from air inleakage; and
- Provide holdup and allows “plateout” of the fission products that may leak out from the closed MSIV during post-accident conditions. This is the only function of the main condenser and low pressure turbine exhaust hood that is within the scope of SLR.

The main condenser is a two-shell, single-pass, divided water box, deaerating type condenser. During plant operation, steam from the last-stage, low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings.

<u>Boundary</u>

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The condensate and feedwater system boundaries are reflected on the SLRBDs listed below:

- H-11602-SLR
- H-11603-SLR
- H-11604-SLR
- H-16062-SLR
- H-21013-SLR
- H-21037004-SLR
- H-21038-SLR
- H-26000-SLR

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.
(2) The NSR MSIV leakage to main condenser drain pathway is in-scope in accordance with 10 CFR 54.4(a)(2) for holdup and plate-out of radioactive isotopes during hypothetical DBAs.

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

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

FSAR References

Unit 1 Sections 11.3 and 11.8
Unit 2 Sections 9.5.10, 10.4.1, and 10.4.7

Components Subject to AMR

Table 2.3.4-1 lists the condensate and feedwater 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 and Feedwater System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (Main condenser) shell	Holdup and plateout
Heat exchanger (Main condenser) tubes	Holdup and plateout
Heat exchanger (Main condenser) tubesheet	Holdup and plateout
Low pressure turbine hood	Holdup and plateout
Piping and piping components	Leakage boundary (spatial)
Thermowell	Leakage boundary (spatial)
Valve body	Leakage boundary (spatial) Pressure boundary

2.3.4.2 Main Steam System

Description

The MS system is designed to perform the following functions:

- Transport steam produced in the reactor to the turbine-generator from warmup to full-power operation for the production of electricity
- Provide steam for the second-stage reheater, steam jet air ejectors, turbine steam sealing system, low-load operation of the reactor feed pump turbines, and off-gas system preheaters
- Provide a means of heat dissipation for heat generated by the nuclear steam supply system in the event the heat generated is in excess of that required for turbine-generator operation

The MS piping consists of four 24 inch outside diameter lines from the outboard MSIVs to the main turbine stop valves and consists of the piping necessary to direct steam to various systems and components. The use of four MSLs permits tests of the turbine stop valves and MSIVs during plant operation, with only minimum load reduction. Drains are provided to remove condensate from the steam lines.

MS system piping from the RPV up to and including the outboard MSIV on each of the four MSLs is included in the scope of the nuclear boiler system.

In support of the MSIV alternate leakage treatment pathway, which is credited for AST, portions of the RWCU, RCIC, auxiliary drains and vents, off gas, reheat steam, and sampling systems that support the AST holdup and plateout functions are included within the scope of the MS system.

Boundary

For the purposes of this screening evaluation, the system boundaries are defined based on the P&IDs and component system designations. The MS system boundaries are reflected in the SLR boundary drawings listed below:

- H-11018-SLR
- H-11025-SLR
- H-11174-SLR
- H-11601-SLR
- H-11602-SLR
- H-11612-SLR
- H-16062-SLR
- H-16188-SLR
- H-16334-SLR
- H-21012-SLR
- H-21013-SLR
- H-21024-SLR
- H-21025-SLR
- H-21031-SLR
- H-21046-SLR
- H-21056-SLR

- H-21205-SLR
- H-26000-SLR
- H-26023-SLR
- H-26036-SLR
- H-26045-SLR
- H-44824-SLR

The MS system interfaces with the condensate and feedwater system at the main condensers and with the nuclear boiler system at the outboard MSIVs shown on drawings H-16062-SLR and H-26000-SLR.

System Intended Functions

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

(1) The main turbine pressure regulators control turbine control valve positions by adjusting EHC pressure based on MS pressure. The EHC regulators in scope of SLR are 1N11N042A/B and 2N32N301A/B shown on boundary drawings H-11601-SLR and H-21012-SLR, respectively. Technical specifications do not require the regulators to be operable, but transient analysis takes credit for the backup pressure regulator to function to prevent fuel damage in the event of a downscale failure of inservice regulator.

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 holdup and plate-out of radioactive isotopes during hypothetical DBAs.

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

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

FSAR References

Unit 1 Section 4.5 and 4.6
Unit 2 Sections 5.5.4, 5.5.5, 5.5.9, and 10.3

Components Subject to AMR

Table 2.3.4-2 lists the MS 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 - Main Steam System Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Closure)	Mechanical closure
Heat exchanger (Offgas pre-heater) channel head	Holdup and plateout
Heat exchanger (Offgas pre-heater) shell	Holdup and plateout
Heat exchanger (Offgas pre-heater) tubes	Holdup and plateout
Heat exchanger (Offgas pre-heater) tubesheet	Holdup and plateout
Orifice	Holdup and plateout
Piping and piping components	Holdup and plateout
Valve body	Holdup and plateout

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

2.4.1 Primary Containment

Description

The primary containment consists of a drywell, which encloses the reactor vessel and recirculation pumps, a pressure suppression chamber (torus) which stores a large volume of water, and a connecting vent system between the drywell and the suppression chamber.

Drywell

The drywell is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion. The drywell is enclosed in a reinforced concrete structure for shielding purposes; herein referred to as the drywell shield wall. Resistance to deformation and buckling of the drywell plate is provided in areas where the concrete backs up the steel shell. The drywell is separated from the reinforced concrete by a gap of approximately 2 inches. Shielding over the top of the drywell is provided by removable, segmented, reinforced concrete shield plugs. The plug sides and bottom surfaces are lined with stainless steel. The concrete outside of the drywell, including the drywell shield wall, is evaluated with the miscellaneous structural commodities AMR.

During erection, the drywell was supported on the circular skirt welded to the bottom portion of the drywell sphere. This cylindrical skirt was anchored to the concrete foundation of the reactor building and received all erection loads of the drywell. In the skirt an access hatch was provided to facilitate work inside the skirt. The skirt was cut from the drywell after the permanent concrete support was constructed. Thus, the drywell was separated from its temporary support. The skirt was left in place and was buried in foundation concrete and does not perform an SLR function.

Personnel and Equipment Access Locks

In addition to the drywell head, one double-door airlock and two bolted equipment hatches provide access into the drywell. The bolted top closure is made with a double tongue and groove seal which permits periodic checks.

The control rod removal hatch access for the drywell is leak tight due to testable double compression seals. This hatch is bolted in place and permits extensive maintenance of the drive mechanism if required.

Access to the pressure suppression chamber is provided at two locations. These are two manhole entrances with double-gasketed bolted covers connected to the chamber by steel pipes.

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 contains the suppression pool and the air space above the pool. The suppression chamber transmits seismic loading to the reinforced concrete foundation slab of the reactor building. Space is provided outside the chamber for inspection.

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 80 downcomer pipes which terminate below the water level of the suppression pool. The vent lines include jet deflectors which span the openings of the vent lines.

The torus is located below and around the drywell. It is supported by 16 pairs of columns with sliding bases. Four shear ties are provided to resist the forces generated due to earthquake. This vent header has the same shape as the torus and is supported by struts from a ring girder provided in the torus. These struts are hinged at the base and top to allow for differential horizontal movements between the vent header and the torus.

Penetration Assemblies - Mechanical

Pipe penetrations are of two general types; i.e., those that accommodate thermal movement (hot), and those that experience relatively little thermal movement (cold).
Some piping penetrations, such as those used for the steam lines, have special provisions for thermal movement. In these penetrations, the process line is enclosed in a guard pipe attached to the MSL through a multiple head fitting. This fitting is a one-piece forging with integral flues and is designed to meet all requirements of the ASME Code, Section III, Subsection B.

The guard pipe and flued head are designed to the same pressure requirements as the process line. The process line penetration sleeve is welded to the drywell and extends through the biological shield where it is welded to a two-ply expansion bellows assembly that is welded to the flued-head fitting. The pipe is guided through pipe supports at the end of the penetration assembly to allow steam line movement parallel to the penetration and limit pipe reactions of the penetration to allowable stress levels.

Where necessary, the penetration assemblies are anchored outside the primary containment to limit the movement of the line relative to the primary containment. The bellows accommodates the relative movement between the pipe and the primary containment shell.

Penetration Assemblies - Electrical

Electrical penetration seals were designed to accommodate the electrical requirements of the plant. These are functionally grouped into six functional categories. All electrical penetration assemblies 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 primary containment structure.

The interior of the electrical penetration assemblies are included within the scope of electrical commodities (Section 2.5). Penetration welds and seals for electrical penetration assemblies are included within the scope of primary containment.

Refueling Bellows

The refueling bellows assembly forms a seal between the reactor vessel and the surrounding drywell to permit flooding of the space (reactor well) above the vessel during refueling operations. The assembly is welded to the reactor bellows support skirt and the reactor well seal bulkhead plate. The reactor bellows support skirt is welded to the reactor vessel shell flange, and the reactor well seal bulkhead plate bridges the distance to the drywell shield wall.

RPV Pedestal

The pedestal consists of two concentric steel shells with concrete fill in between the shells to provide mass and stability. Stiffeners are provided at different locations to distribute the load uniformly over larger areas of the shell. The pedestal supports the RPV, reactor shield wall, intermediate platforms, CRD platform, pipe-whip restraints, pump restraints, pipe hangers, and snubbers. The bottom of the pedestal is anchored to a base slab by means of anchor bolts which transfer the loads to the reactor building foundation. The reactor shield wall columns are directly welded to the top of the pedestal.

Reactor Shield Wall (Sacrificial Shield Wall)

The reactor shield wall consists of 12 buildup steel columns with steel liner plate welded on both sides of the column flanges. A liner plate is provided on the outside flange of the core area for radiation shielding. Intermediate ring beams are provided at various levels to accommodate the restraints. The reactor shield wall is rigidly connected at the base to RPV pedestal and laterally supported by a star truss. The star truss transfers seismic and other forces from the reactor vessel and the reactor shield wall to the drywell shield wall.

Boundary

The evaluation boundary for the primary containment structure as defined in this AMR includes internal concrete and internal steel structures, and platforms and their supports attached to the torus. The mechanical portions of the primary containment are included in the component's respective mechanical AMR. This includes the mechanical portions of instrumentation and controls, isolation valves, piping, and piping components. Miscellaneous structural commodities are addressed in Section 2.4. Section 2.4 also addresses concrete outside of the drywell, including the drywell shield wall and drywell support pedestal. Structural commodity components such as RPV lateral supports (ASME Class I supports), hangers, component supports, insulation, and fire barriers are evaluated in Section 2.4.

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.

(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.

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

FSAR References

Unit 1 Sections 4.2.4, 5.1, 5.2.2, and K.3
Unit 2 Sections 3.8.2 and 5.4.6

Components Subject to AMR

Table 2.4-1 lists the Primary Containment 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 Components Subject to Aging Management Review

Component Type	Component Intended Function
Bolting (Containment closure)	Pressure boundary Structural support
Bolting (Structural)	Structural support
Concrete elements: anchors	Structural support
Concrete elements: embedments	Structural support
Concrete: interior (drywell equipment foundations)	Structural support
Concrete: interior (drywell equipment foundations) (accessible)	Structural support
Concrete: interior (drywell equipment foundations) (inaccessible)	Structural support
Downcomers	Direct flow Pressure boundary Structural support
Drywell shell, drywell head, drywell shell in sand pocket regions (accessible)	HELB shielding Missile barrier Pressure boundary Shelter, protection Structural support

Component Type	Component Intended Function
Drywell shell, drywell head, drywell shell in sand pocket regions (inaccessible)	HELB shielding Missile barrier Pressure boundary Shelter, protection Structural support
High-strength bolting	Structural support
Jet deflectors	Shelter, protection HELB shielding
Moisture barrier	Shelter, protection
Penetration assemblies - containment spares, access manholes, inspection ports	Shelter, protection Pressure boundary Structural support
Penetration assemblies - electrical	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support
Penetration assemblies - mechanical (bellows)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support
Penetration assemblies - mechanical (guard pipe)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support
Penetration assemblies - mechanical (sleeves)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support
Penetration assemblies - mechanical piping (adapters)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support
Personnel airlock, equipment hatch, suppression chamber manhole entrances, CRD hatch, seismic restraint inspection ports, including locks, hinges, and closure mechanisms	Flood barrier HELB shielding Missile barrier Pressure boundary
Reactor shield wall (columns, beams, liner, doors)	Structural support

Component Type	Component Intended Function
Reactor shield wall (inaccessible)	Radiation shielding
Reactor well seal bulkhead plate	Pressure boundary
Refueling water seal assembly (Including reactor bellows support skirt, reactor well seal bulkhead plate)	Structural support Water retaining boundary
RPV pedestal	Structural support
Seals and gaskets	HELB shielding Pressure boundary
Service level I coatings	Maintain adhesion
Sliding surfaces (drywell interior platform sliding plates)	Structural support
Structural steel	Structural support
Structural steel (torus internal catwalk support columns, platforms, drywell interior platforms, stabilizers, radial beam seats, etc.)	Structural support
Support members, welds, bolted connections, support anchorage to building structure	Structural support
Torus shell	Flood barrier Heat sink HELB shielding Missile barrier Pressure boundary Structural support
Torus shell, ring girders	Flood barrier Heat sink HELB shielding Missile barrier Pressure boundary Structural support
Torus vent lines, vent header	Flood barrier Heat sink HELB shielding Missile barrier Pressure boundary Structural support
Vent line bellows	Flood barrier Pressure boundary Structural support
Vent line jet deflectors	Shelter, protection HELB shielding

2.4.2 Component Supports and Structural Commodity Group

Description

The component supports and structural commodity group shares material and environment properties allowing common programs across all in-scope structures to manage their aging effects. The component supports and structural commodities are located in the structures that are within the scope of SLR and include:

- Anchorage/embedment - Components that facilitate structural attachment to concrete are considered to be anchorage/embedment components within the scope of SLR.
- ASME Class 1, 2, 3, and MC Supports - The hangers, snubbers, and pipe restraints that support SR components in the scope of SLR.
- Bird screen - The bird screens that shelter and protect components in the scope of SLR.
- Cabinet, panel, rack, and other enclosure – The electrical and instrumentation enclosures for in-scope cabinets, junction boxes, instrument panels and racks and other electrical equipment.
- Cable tray - The conduits, raceways, and trays system that provide support for a cable system with cables selected, routed, and located to survive the DBEs established for this plant.
- Doors - The doors that shelter and protect components in the scope of SLR.
- Insulation - Insulation is provided in various locations outside the drywell to help retain heat in the process piping and equipment, to prevent moisture from condensing on cold surfaces, to protect equipment and personnel from high temperatures, to prevent piping from freezing in cold areas of the plant, and to protect heat tracing from damage.
- Jacketing - Metallic Jackets serve to protect the insulation from environmental attack and fix the insulation in place.
- Joint and penetrations seals - Joint and penetration seals within the scope of SLR include material seals used for mechanical and electrical penetrations in (non-containment) walls, floors and ceilings that are designed to provide structural support, maintain the structural pressure barrier or act as a flood, radiation, or HELB shielding. Fire barrier penetration seals are included in the fire barrier commodity group.
- Non-ASME class supports - The hangers, snubbers, pipe restraints, tube tray (cable tray), and HVAC duct supports that support SR components in the scope of SLR.
- Penetration sleeves - Penetration sleeves provide a means for supporting and sealing mechanical and electrical penetrations through walls, floors, and other barriers outside of containment. Penetration sleeves are typically provided for openings through barriers for pipe, conduit, instrumentation, bus ducts, HVAC ducts, and cable trays. Seals provide pressure, radiation, fire barrier and environmental integrity.
- Pipe restraint - The pipe restraints support components in the scope of SLR.
- Structural bolting - Bolting providing structural support to SLR component supports or bulk structural commodities are within the scope of SLR. Structural bolting not included as part of this commodity is structural bolting associated with primary containment, structural bolting associated with building structures, and structural bolting associated with crane members and connections.

Boundary

The boundary for the component supports and structural commodity group is the anchorage/embedment, piping and duct supports, cable trays, cabinet, panel, racks, insulation and jacketing, penetration seals and sleeves, bird screens, doors and structural bolting associated with plant systems and equipment that are in-scope for SLR or are located within structures containing SR components.

The component supports and structural commodity group is located in structures reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

(1) Provides physical support, shelter, and protection for SR SSCs.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 1 Sections 5.3.2.2, 7.3.4.3, 8.8, 12.2.15.1, and 12.3.3.2.1
Unit 2 Sections 3.6.5.1, 3.7A.3.16, 3.8D.1, 3.10.2.1.1, and 8.3

Components Subject to AMR

Table 2.4-2 lists the component supports and structural commodity group component types that require an AMR and their associated component intended functions.

Table 3.5.2-2 provides the results of the AMR.

Table 2.4-2 - Component Supports and Structural Commodity Group Components Subject to Aging Management Review

Component Type	Component Intended Function
Anchorage/embedment	Structural support
ASME Class 1 piping supports	Structural support
ASME Class 1 structural bolting	Structural support
ASME Class 1 supports	Structural support
ASME Class 2 and 3 piping and ducts supports	Structural support
ASME Class 2 and 3 structural bolting	Structural support
ASME Class MC piping supports	Structural support
ASME Class MC structural bolting	Structural support
Bird screen	Shelter, protection
Cabinet, panel, rack, and other enclosure	Shelter, protection Structural support
Cable tray	Shelter, protection Structural support
Doors	Shelter, protection
High-strength bolting	Structural support
Insulation	Insulate (thermal)
Jacketing	Thermal insulation jacket integrity
Joint and penetration seals	Flood barrier HELB barrier Pressure boundary Shelter, protection Shielding
Non-ASME Class supports	Structural support
Non-ASME Class supports (SFP)	Structural support
Penetration sleeves	Flood barrier HELB barrier Shelter, protection Shielding
Pipe restraint	HELB Barrier Pipe whip restraint Structural support
Reflective metal insulation	Insulate (thermal)
Structural bolting	Structural support

2.4.3 Concrete Commodity Group

Description

The concrete commodity group shares material and environment properties allowing common programs across all in-scope structures to manage their aging effects. The concrete commodity group is made up of concrete components located in structures that are in-scope. The concrete components include foundations, exterior walls, interior walls, roof, ceilings, pedestals, slabs, concrete at locations of expansion and grouted anchors, curbs, duct banks, masonry walls, and floors.

The concrete commodity group excludes the concrete components located in the primary containment. These components were evaluated with the primary containment in Section 2.4.1 and Table 3.5.2-1. The concrete commodity group excludes the concrete components with a FP intended function. These components were evaluated in the fire barrier commodity group in Section 2.4.7 and Table 3.5.2-7.

Boundary

The boundary for the concrete commodity group is the concrete that makes up the plant structures in-scope, excluding primary containment and concrete with a FP intended function.

The concrete commodity group is located in structures reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

(1) Provides physical support, shelter, and protection for SR SSCs.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 1 Sections 12.2.15.2.4, 12.2.15.2.8, 12.2.15.2.9, 12.2.15.2.14, and 12.5
Unit 2 Sections 3.8.4.6.1, 3.8.5, and 3.8.6.1.3

Components Subject to AMR

Table 2.4-3 lists the concrete commodity group component types that require an AMR and their associated component intended functions.

Table 3.5.2-3 provides the results of the AMR.

Table 2.4-3 - Concrete Commodity Group Components Subject to Aging Management Review

Component	Component Intended Function
Building concrete at locations of expansion and grouted anchors, grout pads for support base plates	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support
Concrete (accessible areas): all	Direct flow Flood barrier HELB barrier Missile barrier Pressure boundary Shelter, protection Structural support
Concrete (accessible areas): all	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support
Concrete (accessible areas): below-grade exterior, foundation	Flood barrier Shelter, protection Structural support
Concrete (accessible areas): exterior above- and below-grade, foundation	Flood barrier Shelter, protection Structural support
Concrete (accessible areas): exterior above- and below-grade, foundation, interior slab	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support
Concrete (accessible areas): interior and above-grade exterior	Direct flow Flood barrier HELB barrier Missile barrier Pressure boundary Shelter, protection Structural support

Component	Component Intended Function
Concrete (inaccessible areas): all	Flood barrier HELB barrier Missile barrier Pressure boundary Shelter, protection Structural support
Concrete (inaccessible areas): below-grade exterior, foundation	Flood barrier Shelter, protection Structural support
Concrete (inaccessible areas): exterior above- and below-grade, foundation	Flood barrier Shelter, protection Structural support
Concrete (inaccessible areas): exterior above- and below-grade, foundation, interior slab	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support
Concrete (inaccessible areas): foundation	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support
Concrete: all	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support
Concrete: exterior above- and below-grade, foundation, interior slab	Direct flow Flood barrier Shelter, protection Structural support
Concrete: interior, above-grade exterior	Direct flow Flood barrier HELB barrier Missile barrier Pressure boundary Shelter, protection Structural support
Masonry walls	Shelter, protection Structural support

2.4.4 Control Building

Description

The purpose of the control buildings is to house the common control room for Units 1 and 2 and associated auxiliaries. The buildings are located between the turbine buildings for Unit 1 and 2. The buildings are reinforced concrete structures with steel framing. The buildings consist of the following major structural components.

- Reinforced concrete foundation mat
- Reinforced concrete floors with reinforced concrete beam and girder framing
- Reinforced concrete or concrete block interior walls and reinforced concrete columns
- Reinforced concrete exterior walls and prestressed exterior wall panels
- Reinforced concrete slab on metal roof deck system supported by steel framing

The MCR is located in the control buildings and is designed to maintain habitability during anticipated operational occurrences and DBAs.

Boundary

The control buildings for Unit 1 and 2 are located between the turbine buildings for Unit 1 and 2. The boundary for the control buildings include the buildings foundation, framing, walls, floors, roof, various interior structure assemblies and doors. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the control buildings are covered in the AMRs applicable to those systems/commodities.

The control buildings boundaries is reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

(1) Provides physical support, shelter, and protection for SR SSCs.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 1 Sections 12.2.3 and 12.3.3.1.1
Unit 2 Section 3.2.1

Components Subject to AMR

Table 2.4-4 lists the control building component types that require an AMR and their associated component intended functions.

Table 3.5.2-4 provides the results of the AMR.

Table 2.4-4 - Control Building Components Subject to Aging Management Review

Component Type	Component Intended Function
Airlock (MCR)	Pressure boundary Shelter, protection
Ballistic shield	Missile barrier
Blowout panels	Pressure boundary Pressure relief Shelter, protection Structural support
Doors	Pressure boundary Shelter, protection
Louver	Structural support
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
Structural bolting	Structural support
Structural steel	Structural support

2.4.5 Cranes, Heavy Loads, Rigging

Description

The cranes, heavy loads, rigging system consists of the fuel preparation machine, grapple, instrument strongback, Unit 1 reactor building crane, refueling platform, RPV serving equipment, spent-fuel cask lift yoke system, Unit 1 turbine building crane, and Unit 2 turbine building crane. The Unit 1 reactor building crane is shared by both Unit 1 and Unit 2. The Unit 2 reactor building crane is not single failure proof and is not used to perform lifts that can affect safety-related components so is not in scope.

- The reactor building crane has the capability to handle loads up to 125 tons using the main hook. This capability includes the handling of shield plugs, reactor vessel heads, drywell heads, steam dryers, steam separators, the 360-degree auxiliary work platform, and the spent-fuel cask. The turbine building crane has the capability to handle loads up to 180 tons using the main hook. The turbine building and reactor building cranes consist of structural girders, end beams, trucks, trolley machinery bed and trucks supporting the mechanical traction drive, hoisting machinery, reeving system, and lifting devices.

- A fuel preparation machine is used to strip the channel from spent-fuel assemblies and to install the used channels on new fuel bundles.
- The general-purpose grapple is a small, hand-actuated tool used generally with the reactor fuel. The grapple can be attached to the reactor building auxiliary hoist, jib crane, and the auxiliary hoists on the refueling platforms. The general-purpose grapple is used to remove new fuel from the vault, place it in the inspection stand, and transfer it to the fuel storage pool. It also can be used to shuffle fuel in the pool and to handle fuel during channeling.
- The head strongback or RPV head carousel/tensioner assembly is used for lifting the RPV head. The strongback is designed to keep the head level during lifting and transport. It is cruciform in shape with four equally spaced lifting points. The instrument strongback is attached to the reactor building crane auxiliary hoist and is used to lift replacement in core detectors from their shipping container.
- The refueling platform is used as the principal means of transporting fuel assemblies back and forth between the reactor well and the fuel storage pool. The platform travels on tracks extending along each side of the reactor well and the fuel storage pool. The platform supports the refueling grapple and auxiliary hoists.
- Fuel assemblies from the SFP are conveyed by the fuel-handling bridge crane into the spent-fuel cask located in the HNP-2 cask pit.
- The spent-fuel cask lift yoke is a single-load-path special lift device designed in accordance with ANSI N14.6 and NUREG-0612 and is rated for a maximum load of 125 tons.

Boundary

The boundary for the cranes, heavy loads, rigging system is the load handling components that comply with NUREG-0612 and large refueling handling equipment normally stored above or in the fuel pool.

The cranes, heavy loads, rigging system is located in structures reflected on the SLRBD listed below.

- E-10173-SLR

Structure Intended Function

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

None.

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

(1) Provides a safe means for handling loads above or near SR components.

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

None.

FSAR References

Unit 1 Sections 1.12.3.10, 1.12.3.11, 10.20, and 12.4.2.4
Unit 2 Sections 9.1.4.1, 9.1.4.2, 9.1.4.3.2, 9.1.5.1.1, and 9.5.8

Components Subject to AMR

Table 2.4-5 lists the cranes, heavy loads, rigging component types that require an AMR and their associated component intended functions.

Table 3.5.2-5 provides the results of the AMR.

Table 2.4-5 - Cranes, Heavy Loads, Rigging Components Subject to Aging Management Review

Component Type	Component Intended Function
Cranes and lifting devices: bridges, structural members, structural components	Structural support
Cranes and lifting devices: rails, bridges, structural members, structural components	Structural support
Cranes and lifting devices: structural bolting	Structural support
Fuel preparation machine framing	Structural support
Refueling platform	Structural support

2.4.6 Emergency Diesel Generator Building

Description

The EDG building (also known as the diesel generator building) is a reinforced concrete Class I structure that is designed to house the diesel generators, local control panels, and emergency switchgear for both Unit 1 and Unit 2.

The EDG building is a one-story box-type structure separated from all other buildings. The foundation is a reinforced concrete rectangular mat, with the bottom of the mat below-grade. The mat bears on very dense clayey fine to medium sand with some clay layers. The exterior walls are above grade. The roof has parapet walls. Reinforced concrete interior walls are provided to physically separate the diesel generators from each other. The EDG building has labyrinth access openings for protection against horizontal tornado missiles. The concrete ballistic shields in the EDG building are evaluated in the concrete commodity group in Section 2.4.3 and Table 3.5.2-3.

Boundary

The boundary for the EDG building encompasses the building foundation, framing, walls, floors, roof, various interior structure assemblies and doors. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the EDG building are covered in the AMRs applicable to those systems/commodities.

The EDG building boundary is reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

(1) Provides physical support, shelter, and protection for SR SSCs.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 1 Sections 1.12.2.3, 8.4.3, and 12.2.6
Unit 2 Sections 2A.5.1.6, 3.2.1.2, 3.5, and 3.8.4.1

Components Subject to AMR

Table 2.4-6 lists the emergency diesel generator building component types that require an AMR and their associated component intended functions.

Table 3.5.2-6 provides the results of the AMR.

Table 2.4-6 - Emergency Diesel Generator Building Components Subject to Aging Management Review

Component Type	Component Intended Function
Doors	Shelter, protection
Louver	Structural support
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
Structural bolting	Structural support
Structural steel	Structural support

2.4.7 Fire Barrier Commodity Group

Description

The fire barrier commodity group shares material and environment properties allowing common programs across all in-scope structures to manage their aging effects. Fire barriers consist of fire-rated doors, fire damper housing, and barrier penetration seals for the respective buildings. They provide separation between safe shutdown trains to ensure a fire in any single area will not prevent safe shutdown, and maintain cable separation. Cable tray FP barriers are a type of barrier that prevents the propagation of fire along the length of cables. Cable tray fire barriers consist of Kaowool insulation (or an equivalent material) wrapped around safe shutdown required cable trays and the steel straps and fasteners used to affix the insulation to the trays. Ventilation duct fire barrier housings, located between adjacent fire areas, are an integral part of the FP barrier and are therefore included with the FP barrier.

The portions of the fire barrier commodity group include cable tray covers, concrete barrier, fire barrier penetration seals, fire damper and vent housing, fire doors, fireproofing, masonry walls, and thermal fiber.

Boundary

The boundary for the fire barrier commodity group includes fire stop sealants, fireproofing, and metallic such as steel. In addition, for SLR, fire doors and structural fire barriers were evaluated as a part of the fire barrier commodity group rather than with the individual structures where they were located.

The fire barrier commodity group are located in structures shown reflected on the SLRBD listed below.

- E-10173-SLR

Structure Intended Function

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

None.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 2 Section 9.5.1

Components Subject to AMR

Table 2.4-7 lists the fire barrier commodity group component types that require an AMR and their associated component intended functions.

Table 3.5.2-7 provides the results of the AMR.

Table 2.4-7 - Fire Barrier Commodity Group Components Subject to Aging Management Review

Component Type	Component Intended Function
Cable tray fire barriers	Fire barrier
Concrete: FP barrier	Fire barrier
Fire barrier penetration seals	Fire barrier
Fire damper and vent housing	Fire barrier
Fire doors	Fire barrier
Fire doors (hinges)	Fire barrier
Fire doors (interior core)	Fire barrier
Fire doors (molding, accessories)	Fire barrier
Fire doors (thrust bearing)	Fire barrier
Fireproofing	Fire barrier
Kaowool hold-down straps and fasteners	Fire barrier Structural support
Masonry walls	Fire barrier
Thermal fiber	Fire barrier

2.4.8 Intake Structure

Description

The intake structure is a reinforced concrete and steel Class I structure designed to protect RHRSW and PSW equipment for both Unit 1 and Unit 2.

The intake structure is built on a reinforced concrete mat with the bottom of the foundation below-grade on firm and dense clayey sands of the Duplin Formation. The major portion of the structure is rectangular with a smaller portion of the structure projecting north.

The intake structure consists of two inlet bays. Each inlet bay is protected by a steel trash rack including a catenary trash rake and a traveling water screen. The trash rack section is separated from the traveling water screen section by a reinforced concrete wall, and the traveling water screen section is separated from the pump bay by another reinforced concrete wall. Water passage through these walls is by an opening from the structure base slab. At normal water level, these openings are below the water level.

Boundary

The boundary for the intake structure includes the foundation, framing, walls, floors, roof, doors, and various interior structure assemblies. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the intake building are covered in the AMRs applicable to those systems/commodities.

The intake structure boundary is reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

(1) Provides physical support, shelter, and protection for SR SSCs.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 1 Sections 1.12.2.2, 2.7.6.4, and 12.2.7
Unit 2 Sections 1.2.7.19, 2A.4.5, 3.4.1, 3.8.4.1, 3.8.5.1, and 15A.5.6.3

Components Subject to AMR

Table 2.4-8 lists the intake structure component types that require an AMR and their associated component intended functions.

Table 3.5.2-8 provides the results of the AMR.

Table 2.4-8 - Intake Structure Components Subject to Aging Management Review

Component Type	Component Intended Function
Ballistic shield	Missile barrier
Doors	Shelter, protection
Louver	Structural support
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
Stop logs	Shelter, protection
Structural bolting	Structural support
Structural steel	Structural support
Trash racks	Filter

2.4.9 Main Stack

Description

The purpose of the main stack is to support and protect monitoring equipment and provide for the monitoring and elevated release of gaseous effluents from the main stack system. The foundation is a reinforced concrete mat octagonal in plan supported by steel H-piles.

The main stack is a concrete cylindrical shape which consists of the following major components:

- Reinforced concrete foundation mat supported on steel “H” piles.
- Reinforced concrete truncated conical cylinder.
- Reinforced concrete internal floors.
- Reinforced concrete loading bay consisting of concrete base slab, external and internal walls, and roof.

Unit 1 shares a single main stack used to discharge gaseous waste with Unit 2. The main stack extends 120 meters above ground level.

Boundary

The main stack is a standalone structure that serves Unit 1 and 2. The boundary for the main stack includes the foundation, framing, walls, floors, roof, doors, and various interior structure assemblies. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the main stack are covered in the AMRs applicable to those systems/commodities.

The main stack boundary is reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

(1) Provides physical support, shelter, and protection for SR SSCs.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

None.

FSAR References

Unit 1 Section 12.2.10
Unit 2 Sections 2A.4.6 and 12.5

Components Subject to AMR

Table 2.4-9 lists the main stack component types that require an AMR and their associated component intended functions.

Table 3.5.2-9 provides the results of the AMR.

Table 2.4-9 - Main Stack Components Subject to Aging Management Review

Component Type	Component Intended Function
Doors	Shelter, protection
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
Steel components: piles	Structural support
Structural bolting	Structural support
Structural steel	Structural support

2.4.10 Radwaste Buildings

Description

Unit 1 and Unit 2 RWBs are Class II structures that house the equipment and control center for the liquid and solid radwaste systems.

The Unit 1 RWB is adjacent to but structurally separated from the reactor buildings. The structure is a reinforced concrete building with a base slab at 100 feet elevation that bears on firm dense and clayey sands with layers of plastic clay.

The Unit 2 RWB is adjacent to but structurally separated from the reactor buildings. The structure is an L-shaped reinforced concrete building with a base slab at 100 feet elevation bears on firm dense and clayey sands with layers of plastic clay.

The RWB addition is evaluated with the RWBs.

Boundary

The boundaries for Unit 1 and Unit 2 RWBs include the foundation, framing, walls, floors, roof, doors, and various interior structure assemblies. The radwaste addition building is included. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the RWBs are covered in the AMRs applicable to those systems/commodities.

The Unit 1 and Unit 2 RWBs boundaries are reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

None.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 1 Sections 2.7.5.2, 2.7.6.2, 12.2.4, 12.2.5, and 12.3.3.1.2
Unit 2 Sections 2A.4.4, 2A.5.1.3, and 3.8.7

Components Subject to AMR

Table 2.4-10 lists the radwaste buildings component types that require an AMR and their associated component intended functions.

Table 3.5.2-10 provides the results of the AMR.

Table 2.4-10 - Radwaste Buildings Components Subject to Aging Management Review

Component Type	Component Intended Function
Doors	Shelter, protection
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
Structural bolting	Structural support
Structural steel	Structural support

2.4.11 Reactor Buildings

Description

The purpose of the reactor buildings is to shelter and support the refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor auxiliary and service equipment. The building is a reinforced concrete structure with a steel superstructure. The building consists of the following major structural components:

- Reinforced concrete foundation mat
- Reinforced concrete exterior walls and prestressed exterior wall panels
- Reinforced concrete floors with reinforced concrete beams and girders framing
- Reinforced concrete interior walls with some blockouts filled with concrete masonry

- Reinforced concrete roof slab on metal roof deck system supported by a steel superstructure
- A structural separation joint sealed with three-bulb water stop is provided at the reactor building end

The reactor buildings completely enclose the reactor and its pressure suppression primary containment system. Also housed within the reactor buildings are the core standby cooling systems, RWCU demineralizer system, SBLC system, CRD system, RPS, and electrical equipment components. The building is designed for minimum leakage so that the SBGT system has the necessary capacity to reduce and hold the building at a sub atmospheric pressure under normal wind conditions. The HPCI rooms and steam tunnel are evaluated with the reactor buildings.

Boundary

The reactor buildings house the reactors for Unit 1 and 2 and includes the HPCI rooms. The boundary for the reactor buildings include the foundation, framing, walls, floors, roof, doors, various interior structure assemblies, and the steam tunnel leading up to the turbine building. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the reactor buildings are covered in the AMRs applicable to those systems/commodities.

The reactor buildings boundaries are reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

(1) Provides physical support, shelter, and protection for SR SSCs.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 1 Sections 6.4.1 and 12.2.1
Unit 2 Sections 3.0, 6.3.2.2.1, and 9.1.2.2.1

Components Subject to AMR

Table 2.4-11 lists the reactor buildings component types that require an AMR and their associated component intended functions.

Table 3.5.2-11 provides the results of the AMR.

Table 2.4-11 - Reactor Buildings Components Subject to Aging Management Review

Component Type	Component Intended Function
Ballistic shield	Missile barrier
Blowout panels	Pressure relief Shelter, protection Structural support
Boral plate	Absorb neutrons
Doors	Shelter, protection
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
New fuel storage racks	Structural support
Railroad airlock	HELB barrier Missile barrier Pressure boundary Shelter, protection
Seismic restraints for spent fuel storage racks	Structural support
SFP gate	Pressure boundary Structural support
SFP liner	Pressure boundary Structural support
Spent fuel storage racks	Structural support
Structural bolting	Structural support
Structural steel	Structural support
Three-bulb water stop	Pressure boundary
Tornado vent frames	Structural support

2.4.12 Switchyard Structures

Description

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits. The existing switchyard serves both circuits. The outdoor switchgear is found in the 500 kV and 230 kV switchyards. The 500 kV switchyard is not in the scope of SLR. The off-site power pathways for SBO which are in-scope for SLR are in the 230 kV switchyards, and these include all equipment from the startup transformers to main 230 kV bus 1 in the 230 kV switchyard. All equipment from the startup transformers up to, and including, the 230 kV line intermediate circuit breakers are supported on reinforced concrete pads founded on compacted soil.

The control buildings for the 230 kV switchyard and the 500 kV switchyard are steel structures with metal siding, built-up roofs, and slab-on-grade floors.

All the transmission towers up to the first circuit breakers in the 500 kV switchyard and towers supporting the transmission lines to the 230 kV line intermediate circuit breakers are steel towers. The transmission towers are founded on concrete bases of various configurations with some supported on compacted soil and others directly on bedrock.

Electrical cables from the transformers are installed in buried concrete duct banks. Manholes are provided along these duct banks for cable installation and access. Duct banks and manholes are evaluated in the concrete commodity group.

Boundary

The switchyard structures serves Unit 1 and 2. The boundary for the switchyard structures includes the 230 kV switchyard, 500 kV switchyard, electrical foundations, and various structural support assemblies. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the switchyard structures are covered in the AMRs applicable to those systems/commodities.

The switchyard structures boundaries are reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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) Performs a function that demonstrates compliance with the Commission's regulations for SBO.

FSAR References

Unit 2 Sections 8.2.1 and 8.2.2.1

Components Subject to AMR

Table 2.4-12 lists the switchyard structures component types that require an AMR and their associated component intended functions.

Table 3.5.2-12 provides the results of the AMR.

Table 2.4-12 - Switchyard Structures Components Subject to Aging Management Review

Component Type	Component Intended Function
Doors	Shelter, protection
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
Structural bolting	Structural support
Structural steel	Structural support
Transmission tower	Structural support

2.4.13 Turbine Buildings

Description

The Turbine Buildings are reinforced concrete and steel frame Class II structures with the main purpose of housing the turbine generator and associated auxiliaries including the condensate and feedwater systems, reactor feed pumps, and the plant instrument and service air compressors.

The turbine buildings are steel and reinforced concrete structures consisting of the following major structural components:

- Reinforced concrete foundation mat
- Reinforced concrete floors self-supporting or supported by structural steel framing
- Reinforced concrete or concrete block interior walls
- Reinforced concrete turbine pedestal resting on concrete mat foundation
- Reinforced concrete (precast) exterior walls
- Reinforced concrete slab on metal roof deck system supported by steel framing

Boundary

The boundary for the turbine buildings include the foundation, framing, walls, floors, roof, doors, and various interior structure assemblies. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the turbine buildings are covered in the AMRs applicable to those systems/commodities.

The turbine buildings boundaries are reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

None.

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

(1) Provides physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

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

FSAR References

Unit 1 Sections 12.2.2 and 12.3.3.1.2

Components Subject to AMR

Table 2.4-13 lists the turbine buildings component types that require an AMR and their associated component intended functions.

Table 3.5.2-13 provides the results of the AMR.

Table 2.4-13 - Turbine Buildings Components Subject to Aging Management Review

Component Type	Component Intended Function
Blowout panels	Pressure relief Shelter, protection Structural support
Doors	HELB barrier Shelter, protection

Component Type	Component Intended Function
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
Structural bolting	Structural support
Structural steel	Structural support

2.4.14 Yard Structures and Tank Foundations

Description

The yard structures includes various concrete and steel structures in the scope of SLR. These include the walls and foundation of condensate storage tank (CST), the foundation of the nitrogen storage tank, the service water valve pit boxes, the foundation of the fire pump house, the foundations of the two fire water storage tanks, the foundations of the two FP diesel pump fuel tanks, and the underground reinforced concrete duct runs and pull boxes between the Class 1 structures. Concrete components are evaluated in the concrete commodity group.

- Walls and foundation of CST - The horizontal missile-proof retaining walls and foundation around CST and transfer pumps are Class I structures. The walls have the capacity to contain the contents of the storage tank to preclude spillage of condensate water to the environment in the event that the tank suffers a leak. The bottom of CST is at grade.
- Liquid nitrogen storage tanks foundations - The liquid nitrogen storage tanks and foundations are Class I structures. The liquid nitrogen storage tanks are located on each side of the HNP-1 reactor building railway airlock and are used in HNP-2 as a source of motive gas for essential air-operated valves and instruments. The liquid nitrogen tank provides the SR back-up supply of motive gas for the drywell inserting system and the drywell pneumatic system. Safe Shutdown Pathways 1 and 2 in the fire hazards analysis (FHA) rely upon the liquid nitrogen tank to achieve safe shutdown in the event of a fire.
- Service water valve pit boxes - The service water valve pit boxes are in-scope as they contain in-scope piping.
- FP pump house foundation - The FP pump house contains FP equipment that is shared by both HNP-1 and HNP-2. The foundations for the FP pump house, water storage tanks, and diesel pump fuel tanks are in-scope. The concrete block walls and fire doors in the FP pump house are addressed in fire barrier commodity group.
- Duct runs and pull boxes - The reinforced concrete duct runs and pull boxes that traverse the yard between various Class I structures as well as turbine building are in-scope. These duct runs are used for routing SR circuits and provide protection to them. The pull boxes are designed to meet seismic conditions. Boxes installed out of traffic patterns extend above-grade and have a cover of aluminum tread plate with reinforced T-sections on the bottom of the cover plate. Steel angles are embedded in the tops of boxes, and cover plates are secured to the angles with bolts.

Boundary

The boundary for the yard structures and tank foundations encompasses the foundation of the CST, foundation of the nitrogen storage tank, foundation for the FP pump house, the foundations for the two FP water storage tanks, the underground concrete duct runs and pull boxes between class I structures, and service water valve pit boxes. Mechanical systems, electrical equipment, component supports, concrete components and associated commodities inside the reactor buildings are covered in the AMRs applicable to those systems/commodities.

The yard structures and tank foundations boundaries are reflected on the SLRBD listed below:

- E-10173-SLR

Structure Intended Function

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

(1) The CST walls and foundation provides physical support, shelter, and protection for SR SSCs.

(2) The nitrogen storage tank foundations provide physical support, shelter, and protection for SR SSCs.

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

(1) The service water valve pits provide physical support, shelter, and protection for NSR SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1).

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

(1) The CST walls and foundation provide physical support, shelter, and protection for SSCs 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).

(2) The FP diesel pump fuel tanks foundations provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for FP (10 CFR 50.48).

(3) The FP pump house foundation provides physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for FP (10 CFR 50.48).

(4) The FP storage tanks foundations provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for FP (10 CFR 50.48).

(5) The nitrogen storage tank foundations provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for FP (10 CFR 50.48).

FSAR References

Unit 1 Sections 1.6.10, 1.12.2.8, 11.9.3, and 12.3.3.1.1
Unit 2 Sections 3.2.1.2, 3.8.4.1, 3.8.5.1, 9.2.6.2, and 12.3.2.2.6

Components Subject to AMR

Table 2.4-14 lists the yard structures and tank foundations component types that require an AMR and their associated component intended functions.

Table 3.5.2-14 provides the results of the AMR.

Table 2.4-14 - Yard Structures and Tank Foundations Components Subject to Aging Management Review

Component Type	Component Intended Function
Cover plates: pull boxes	Flood barrier Shelter, protection
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support
Pit boxes	Flood barrier Shelter, protection
Steel frame: pull boxes	Structural support
Structural bolting	Structural support
Structural steel	Structural support

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL AND INSTRUMENTATION AND 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 SLR scoping criteria contained in 10 CFR 54.4. Section 2.1 provides the methodology for determining the electrical components/commodities within the scope of 10 CFR 54.4 that meet the screening requirements contained in 10 CFR 54.21(a)(1). The components/commodities that meet these screening requirements are identified in this section. These identified electrical components/commodities require an AMR for SLR.

For the electrical screening process, the components are grouped into electrical component commodity groups, such as insulated cables and connections, metal-enclosed bus, relays, various instruments, etc. The commodity groups are industry standard electrical component commodity groupings. The screening process evaluates commodity groups on their functional status as passive electrical components, or as active electrical components, in accordance with 10 CFR 54.21(a)(1)(i). Components that are short-lived (such as EQ components, which have specified component lifetimes) are also screened out, in accordance with 10 CFR 54.21(a)(1)(ii).

The evaluation of the electrical component commodity groups is described in Section 2.5.1. The electrical commodities subject to AMR are described in Section 2.5.2. Supports for electrical cables, cable trays, conduits, cabinets, racks, and enclosures are addressed in the Hangers and Supports Commodity Group (Section 2.4). Mechanical interfaces are addressed in the appropriate mechanical sections of the SLR.

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, controlled component database, 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.

2.5.1.2 Application of Screening Criterion 10 CFR 54.21(a)(1)(i) to the Electrical and I&C Components and Commodities

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 bus
- Cable connections (metallic parts)
- Cable tie-wraps
- Fuse holders (not part of active equipment)
- High voltage insulators

- Metal-Enclosed Bus
- Non-EQ Insulated cables and connections
- Non-EQ Electrical and I&C penetration assemblies
- Passive electrical equipment subject to 10 CFR 50.49 EQ requirements
- Switchyard bus and connections
- Transmission conductors and connectors
- Uninsulated ground conductors

2.5.1.3 Elimination of Electrical and I&C Commodity Groups with No License Renewal Intended Functions

The following electrical and I&C commodity groups were determined to not have a LR intended function:

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 CLB requirements for HNP 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. Seismic qualification of cable trays does not credit the use of electrical cable tie-wraps. Cable tie-wraps are not credited in the HNP 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.

Uninsulated Ground Conductors

Uninsulated ground conductors are electrical conductors (e.g., copper cable, copper 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 building structural steel. 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 conductors enhance the capability of the electrical system to withstand electrical system disturbances (e.g., electrical faults, lightning surges) for equipment and provide 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 at HNP are not credited with providing any FP intended function (i.e., lightning protection via lightning rods or masts) and have no other SLR intended function; therefore, they are excluded from further review and 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. 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 EQ Program. This is because electrical and I&C components (with replacement schedules) and commodities 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 10 CFR 50.49 Environmental Qualification of Electric Equipment program are subject to AMR in accordance with the screening criterion of 10 CFR 54.21(a)(1)(ii). See Section 4.4 for the evaluation of the Environmental Qualification of Electric Equipment TLAA. The remaining commodities, all, or part of which are not in the 10 CFR 50.49 Environmental Qualification of Electric Equipment program, require AMR.

2.5.2 Electrical and I&C Commodity Groups Subject to Aging Management Review

After applying the screening criteria discussed above, including the guidance in NEI 17-01, the following commodities require AMR and are discussed below.

<u>Electrical Insulation for Non-EQ Insulated Cables and Connections</u>

The insulated cables and connections commodities are separated for AMR into subcategories based on their treatment in NUREG-2191:

- Insulation for electrical cables and connections
- Insulation for electrical cables and connections used in instrumentation circuits
- Insulation for inaccessible medium-voltage cable
- Insulation for inaccessible I&C cable
- Insulation for inaccessible low voltage power cable

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 AMP. 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 AMP. Components in the Environmental Qualification of Electric Equipment AMP are replaced prior to the expiration of their qualified life. Accordingly, all insulated cables and connections within the Environmental Qualification of Electric Equipment AMP are replacement items under 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR. TLAAs associated with electrical/I&C components within the Environmental Qualification of Electric Equipment AMP 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 AMP, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

Switchyard Bus, High Voltage Insulators, Transmission Conductors

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 ML02090464). An evaluation was performed 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 insulators, transmission conductors, and metal-enclosed bus 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 AMP. Thus, these commodities meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR. The electrical interconnection between HNP and the offsite transmission network and the off-site power recovery paths following an SBO are shown in Figure 2.5-1.

Electrical and I&C Penetration Assemblies

All of the electrical/I&C penetration assemblies in the scope of SLR are included in the Environmental Qualification AMP (B.2.2.1). As such, these components have a qualified life that is described in program documents and, per 10 CFR 54.21(a)(1)(ii), they are not subject to an AMR.

Metal-Enclosed Bus

There are 30’ sections of MEB (bus bar) that are in-scope for SLR to meet the SBO criterion in 10 CFR 54.4(a)(3), found in both Units 1 and 2. These sections of MEB are used for an alternative alignment for buses F and G and are also available for an SBO response to connect 4160 volt bus F to 600 volt buses C and D. It is almost never loaded during normal plant operation. The bus bar is copper and the bolted joints are plated. The bus bar is protected with mylar (insulation) and a urethane coating. The insulation is rated as Class B. The ductwork for the MEB is armor-clad (tightly sealed ductwork) that is suspended from the ceiling, located on elevation 130’ in the Control Building. The environment in the Control Building is controlled. The armor-clad ductwork is comprised of galvanized steel and is painted.

This MEB that is within the scope of SLR is not included in the Environmental Qualification of Electric Equipment AMP (B.2.2.1), and therefore is subject to an 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 (bus bar), cable bus is comprised of an enclosed metal duct that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus typically has louvers (or openings, such as slots) in the ductwork and is routed above ground like metal-enclosed bus. The Hatch cable bus in scope of SLR is routed in ducts which have fine mesh top and bottom panels. The cable is 4160 volts alternating current (VAC), and is routed from the Start-Up Transformers (E/F/G) to the emergency switchgear.

The cable bus that is within the scope of SLR is not included in the Environmental Qualification of Electric Equipment AMP (B.2.2.1), and therefore meets the criterion of 10 CFR 54.21(a)(ii) and is subject to an AMR.

Electrical Cable Connections (metallic parts)

NUREG-2191, Section XI.E6 addresses the metallic portion of electrical connections, to demonstrate that the connections show electrical integrity. This is a one-time inspection, to be performed prior to the SPEO. The connection types include bolted connections, fusion connections, and splices. The range of connections includes normal operating voltages except for high-voltage (>35 kV) connections. The subject electrical connections may be utilized for active or passive end devices (components).

Fuse Holders

The cables and connections commodity group includes fuse holders (or fuse blocks). These components are comprised of a terminal block and a fuse, which is held in place by a metallic clip or clamp. Consistent with NUREG-2191, Section XI.E5 (Fuse Holders), the screening of fuse holders (and the metallic clamp) applies to those items which are not part of a larger assembly (an electrical enclosure that also contains active electrical components). Fuse holders inside the enclosure of an active electrical assembly, such as switchgear, power supplies, power inverters, battery chargers, circuit boards, and other electrical enclosures with active components (an active electrical assembly) are considered to be piece parts of the active enclosure. Because piece parts and subcomponents in such an active electrical assembly are routinely inspected and regularly maintained as part of the plant's normal maintenance and surveillance activities, these fuse holders (in active enclosures) are not subject to AMR.

Hatch has identified electrical enclosures with just fuses and terminal blocks both Unit 1 and Unit 2 (as passive electrical assemblies). These will be evaluated for environmental stressors, aging mechanisms, and aging effects (including manipulation of the fuse and any mechanical stress to the fuse clip). These electrical enclosures are not part of the Environmental Qualification of Electrical Equipment AMP (B.2.2.1) and therefore meet the criterion of 10 CFR 54.21(a)(ii) and are subject to an AMR.

The in-scope electrical and I&C component commodity groups identified are listed in Table 2.5-1.

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.

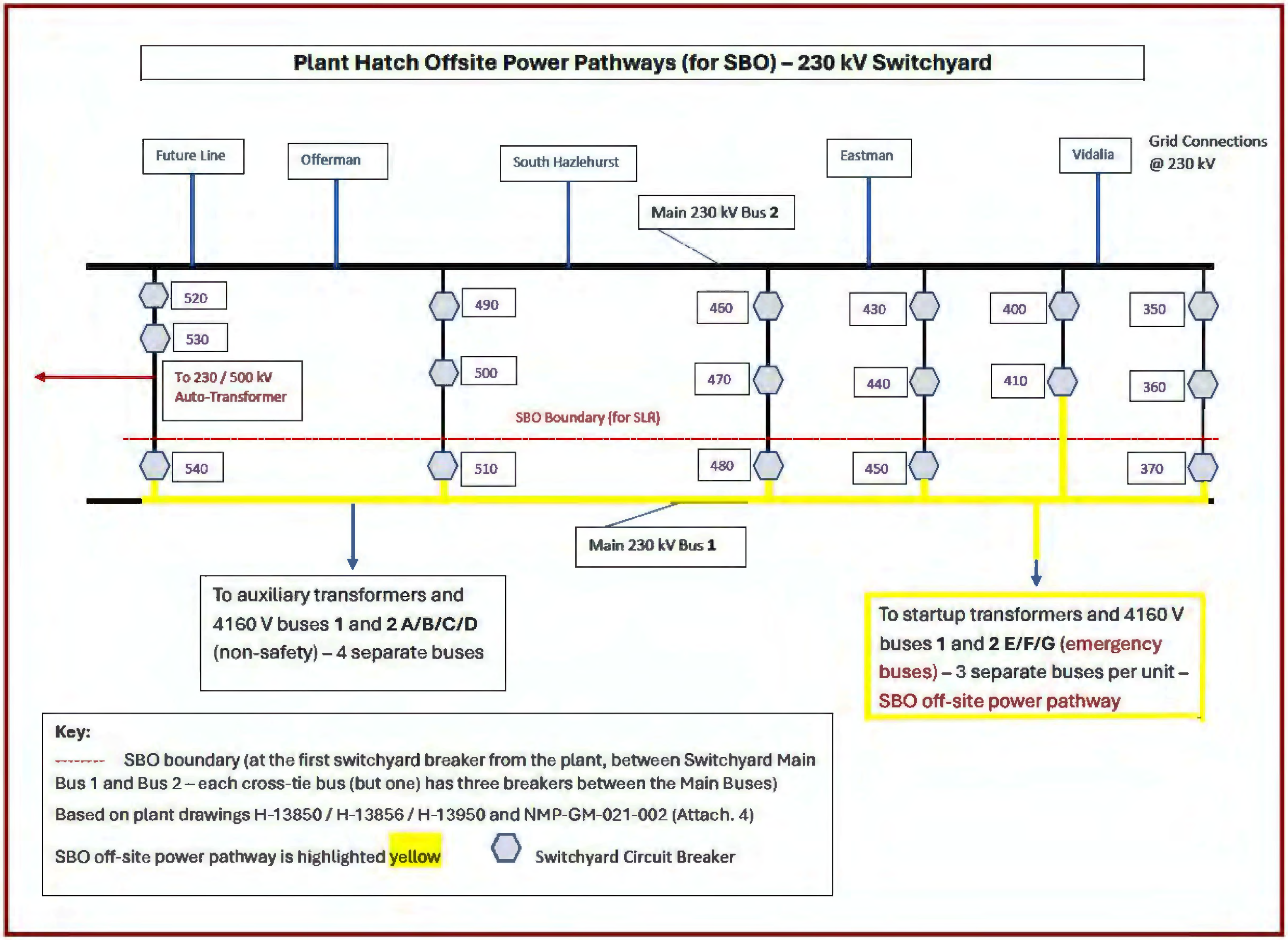
Table 2.5-1
Electrical and I&C Component Groups
Installed at HNP for In-Scope Systems

Alarm Units	Elements	Meters	Splices
Analyzers	Fuses	Motor Control Centers	Surge Arresters
Annunciators	Fuse Holders	Motors	Switches
Batteries	Generators	Power Distribution Panels	Switchgear
Cable Bus	Heat Tracing	Power Supplies	Switchyard Bus
Chargers	Electric Heaters	Radiation Monitors	Terminal Blocks
Circuit Breakers	High-Voltage Insulators	Recorders	Thermocouples
Converters	Indicators	Regulators	Transducers
Communication Equipment	Insulated Cables and Connections	Relays	Transformers
Electrical Controls and Panel Internal Component Assemblies	Inverters	RTDs	Transmitters
	Isolators	Sensors	Transmission Conductors
	Light Bulbs	Solenoid Operators	
Electrical/I&C Penetration Assemblies	Load Centers	Signal Conditioners	
	Loop Controllers	Solid State Devices	

Table 2.5-2
Electrical and Instrumentation and Control Systems
Components Subject to Aging Management Review

Structure and/or Component/ Commodity	Component Intended Function(s)
Cable bus	Electrical continuity Insulate (electrical)
Cable connections (metallic parts)	Electrical continuity
Electrical conductor insulation for cables and connections	Electrical continuity
Fuse holders (Not part of active equipment): electrical insulation Fuse holders (Not part of active equipment): metallic clamp	Insulate (electrical) Electrical continuity
High-voltage electrical insulators	Insulate (electrical)
Metal-enclosed bus	Electrical continuity Insulate (electrical)
Switchyard bus and connections	Electrical continuity
Transmission conductors	Electrical continuity

Figure 2.5-1
Restoration of Offsite Power following an SBO Event



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 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 nuclear boiler system, within the Reactor Vessels, Internals, and Reactor Coolant System subsection, this table would be Table 3.1.2-1 and for the reactor recirculation system, it would be Table 3.1.2-2. For the CS 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: CS system, HPCI system, post LOCA hydrogen recombiners system, primary containment purge and inerting system, RCIC system, RHR system, SBGT system, and SBLC system. 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, 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) AMP. Examples include reactor building closed cooling water systems and the closed portions of HVAC 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) AMP. Examples include reactor building closed cooling water systems and the closed portions of HVAC 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. The water that enters the fire water system is assumed to be raw water.	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 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 SBLC 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, 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

Table 3.0-2
Structural Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
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
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. 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
Adverse localized environment	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 Vessel, Internals, and Reactor Coolant System* as being subject to AMR. The systems, or portions of the systems, which are addressed in this section are described in the indicated sections.

- Nuclear Boiler System (Section 2.3.1.1)
- Reactor Recirculation System (Section 2.3.1.2)
- Reactor Pressure Vessel (Section 2.3.1.3)
- Reactor Vessel Internals (Section 2.3.1.4)

3.1.2 Results

The following tables summarize the results of the AMR for the Reactor Vessel, Internals, and Reactor Coolant System.

Table 3.1.2-1, Nuclear Boiler System – Summary of Aging Management Evaluation

Table 3.1.2-2, Reactor Recirculation System – Summary of Aging Management Evaluation

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

Table 3.1.2-4, Reactor Vessel Internals – Summary of Aging Management Evaluation

3.1.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.1.2.1.1 Nuclear Boiler System

Materials

The materials of construction for the nuclear boiler system are:

- Carbon steel
- Cast austenitic stainless steel
- Copper alloy
- Nickel alloy
- Stainless steel

Environments

The nuclear boiler system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Reactor coolant
- Treated water

- Treated water > 140 °F

Aging Effects Requiring Management

The following aging effects associated with the nuclear boiler system require management:

- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Wall thinning - erosion
- Wall thinning - FAC

Aging Management Programs

The following AMPs manage the aging effects for the nuclear boiler 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)
- Bolting Integrity (B.2.3.10)
- BWR Stress Corrosion Cracking (B.2.3.5)
- 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)
- Torus Submerged Components Inspection (B.2.4.2)
- Water Chemistry (B.2.3.2)

3.1.2.1.2 Reactor Recirculation System

Materials

The materials of construction for the reactor recirculation system are:

- Carbon steel
- Cast austenitic stainless steel
- Nickel alloy
- Stainless steel

Environments

The reactor recirculation system components are exposed to the following environments:

- Air – indoor uncontrolled
- Closed cycle cooling water > 140 °F
- Reactor coolant

Aging Effects Requiring Management

The following aging effects associated with the reactor recirculation system require management:

- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the reactor recirculation system components:

- ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)
- ASME Code Class 1 Small-Bore Piping (B.2.3.22)
- Bolting Integrity (B.2.3.10)
- BWR Stress Corrosion Cracking (B.2.3.5)
- Closed Treated Water Systems (B.2.3.12)
- Flow-Accelerated Corrosion (B.2.3.9)
- One-Time Inspection (B.2.3.20)
- Thermal Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.3.8)
- Water Chemistry (B.2.3.2)

3.1.2.1.3 Reactor Pressure Vessel

Materials

The materials of construction for the reactor pressure vessel components are:

- Carbon or low alloy steel with stainless steel cladding
- Carbon steel
- High-strength low alloy steel bolting with yield strength of 150 ksi or greater
- Low alloy steel
- Low alloy steel with stainless steel cladding
- Nickel alloy
- Stainless steel

Environments

The reactor pressure vessel components are exposed to the following environments:

- Air – indoor uncontrolled
- Neutron flux
- Reactor coolant
- Reactor coolant and neutron flux

Aging Effects Requiring Management

The following aging effects associated with the reactor pressure vessel require management:

- Cracking
- Cumulative fatigue damage
- 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)
- Fluence Monitoring (B.2.2.3)
- 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)

3.1.2.1.4 Reactor Vessel Internals

Materials

The materials of construction for the RVI components are:

- Carbon steel with stainless steel cladding
- Cast austenitic stainless steel
- Nickel alloy
- Stainless steel

Environments

The RVI components are exposed to the following environments:

- Reactor coolant
- Reactor coolant and neutron flux

Aging Effects Requiring Management

The following aging effects associated with the RVI 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 RVI components

- ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)
- BWR Vessel Internals (B.2.3.7)
- Water Chemistry (B.2.3.2)

3.1.2.2 Further Evaluation of Aging Management as Recommended by GALL-SLR

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the SLRA. For the Reactor Vessel, Internals, and Reactor Coolant System, those programs are addressed in the following subsections. 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 (TN4878). TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The TLAAs which involve time-dependent fatigue or cyclical loading parameters 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 Reactor Vessel, Internals, and Reactor Coolant System 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 make sure that flaws cannot attain a depth sufficient to threaten the integrity of the welds. However, according to NRC Information Notice 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," the program may not be sufficient to detect pitting and crevice corrosion if general and pitting corrosion of the shell is known to exist. Augmented inspection is recommended to manage this aging effect. Furthermore, this issue is limited to Westinghouse Model 44 and 51 Steam Generators, where a high-stress region exists at the shell-to-transition cone weld. Acceptance criteria are described in Branch Technical Position (BTP) License Renewal and Standardization Branch (RLSB-1) (Appendix A.1 of this SRP-SLR).*

   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 make sure 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 10^{17} neutron per square centimeter [n/cm2] (E >1 mega electron-volt [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 (TN4878). The TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The TLAA which covers aspects of neutron irradiation embrittlement is addressed separately in Section 4.2, "Reactor Pressure Vessel Neutron Embrittlement Analysis," of this SRP-SLR.*

   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 RV material surveillance program monitors neutron irradiation embrittlement of the reactor vessel. The reactor vessel material surveillance program is either a plant-specific surveillance program or an integrated surveillance program, depending on matters such as the composition of limiting materials and the availability of surveillance capsules.*

   In accordance with 10 CFR Part 50 (TN249), Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further NRC staff evaluation is required for a subsequent license renewal (SLR). Specific recommendations for an acceptable AMP are provided in GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance."

   A neutron fluence monitoring program may be used to monitor the neutron fluence levels that are used as time-dependent inputs for the plant's RV neutron irradiation embrittlement TLAAs. These TLAAs are the subjects of the topics discussed in SRP-SLR Section 3.1.2.2.3.1 and "Acceptance Criteria" and "Review Procedure" guidance in SRP-SLR Section 4.2. For those applicants that determine it is appropriate to include a neutron fluence monitoring AMP in their SLRAs, the program is to be implemented in conjunction with the applicant's implementation of an AMP that corresponds to GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance." Specific recommendations for an acceptable neutron fluence monitoring AMP are provided in GALL-SLR Report AMP X.M2, "Neutron Fluence Monitoring."

   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.2.2.3) AMP. The Neutron Fluence Monitoring (B.2.2.3) 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 RV flange leak detection lines of BWR light-water reactor facilities. The plant-specific operating experience (OE) and condition of the RV flange leak detection lines are evaluated to determine if SCC or IGSCC has occurred. The aging effects involving cracking of SS and nickel-alloy RV flange leak detection lines are not applicable and do not require management if: (i) the plant-specific OE does not reveal a history of SCC or IGSCC and (ii) a one-time inspection demonstrates that the effect of aging is not evident. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.*

   The HNP reactor vessel flange leak-off lines are stainless steel and therefore are susceptible to cracking, along with other stainless steel components. OE has shown that SCC of reactor vessel flange leak-off lines and other stainless steel components has not occurred. Therefore, the One-Time Inspection (B.2.3.20) AMP will be used to verify the absence of SCC in stainless steel 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 make sure 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. HNP 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. The CLBs that include these types of *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) (TN4878). The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code Section XI.1 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. *Deleted.*

2. *Deleted.*

3. *Cracking due to SCC could occur in SS or nickel-alloy RV flange leak detection lines of PWR light-water reactor facilities. The plant-specific OE and condition of the RV flange leak detection lines are evaluated to determine if SCC has occurred. The aging effect involving cracking in SS and nickel-alloy RV flange leak detection lines is not applicable and does not require management if: (i) the plant-specific OE does not reveal a history of SCC and (ii) a one-time inspection demonstrates that effect of aging is not evident. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.*

   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 make sure 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. HNP 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 of a plant-specific AMP is recommended to make sure 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 RVI components that are included in the design of a PWR facility. Since the issuance of MRP-227-A on January 9, 2012, EPRI updated its I&E guidelines for the PWR RVI components in TR No. 3002017168, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A)" (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 TR for use as documented in the staff's letters to the EPRI Materials Reliability Program (MRP) dated February 19, 2020 and July 7, 2020 (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: (i) SCC, (ii) irradiation-assisted stress corrosion cracking (IASCC), (iii) fatigue, (iv) wear, (v) neutron irradiation embrittlement, (vi) thermal aging embrittlement, (vii) void swelling and irradiation growth or component distortion, and (viii) thermal or irradiation-enhanced stress relaxation or irradiation-enhanced creep.

The EPRI MRP's functionality analysis and failure modes, effects, and criticality analysis bases for grouping Westinghouse-designed, B&W designed and Combustion Engineering (CE)-designed RVI components into the applicable inspection categories (as evaluated in MRP-227, Revision 1-A) were based on an assessment of aging effects and relevant time-dependent aging parameters through a cumulative 60-year licensing period (i.e., 40 years for the initial operating license period plus an additional 20 years during the initial period of extended operation). The EPRI MRP's assessment in MRP-227, Revision 1-A, did not evaluate the potential impacts of operation of Westinghouse-designed, B&W designed and CE designed reactors during an SLR operating period (60 to 80 years) on the existing susceptibility rankings and inspection categorizations for the RVI components in these designs, as defined in MRP-227, Revision 1-A or the applicable MRP background documents (e.g., MRP-191, Revision 1, for Westinghouse-designed or CE designed RVI components or MRP-189, Revision 2, for B&W designed components). As described in GALL-SLR Report AMP XI.M16A, the applicant may use the MRP-227, Revision 1-A based AMP as an initial reference basis for developing and defining the AMP that will be applied to the RVI components for the subsequent period of extended operation. However, to use this *alternative basis, GALL-SLR Report AMP XI.M16A recommends that the MRP-227, Revision 1-A based AMP be enhanced to include a gap analysis of the components that are within the scope of the AMP. The gap analysis is a basis for identifying and justifying changes to the MRP-227, Revision 1-A based program that are necessary to provide reasonable assurance that the effects of age-related degradation will be managed during the subsequent period of extended operation. The criteria for the gap analysis are described in GALL-SLR Report AMP XI.M16A. If a gap analysis is needed to establish the appropriate aging management criteria for the RVI components, the applicant has the option of including the gap analysis in the SLRA or making the gap analysis and any supporting gap analysis documents available in the in-office audit portal for the SLRA review.*

The SLR applicants for units of a PWR design will no longer need to include separate SLRA Appendix C Section responses in resolution of the Applicant/Licensee Action Item (A/LAIs) previously issued on MRP-227-A because the A/LAIs were resolved and closed by the staff in the April 25, 2019, safety evaluation for MRP-227, Revision 1-A. The sole A/LAI issued by the staff in the safety evaluation dated April 25, 2019, relates to an applicant's methods and timing of inspections that will be applied to the baffle to former bolts or core shroud bolts in the plant design. Since an applicant's resolution of this A/LAI can be appropriately addressed in the "Operating Experience" program element discussion for the AMP and in the applicant's basis document for the AMP, a separate SLRA Appendix C response for the A/LAI is not necessary.

Alternatively, the PWR SLRA may define a plant-specific AMP for the RVI components to demonstrate that the RVI components will be managed in accordance with the requirements of 10 CFR 54.21(a)(3) (TN4878) during the proposed subsequent period of extended operation. Components to be inspected, parameters monitored, monitoring methods, inspection sample size, frequencies, expansion criteria, and acceptance criteria are justified in the SLRA. If the AMP is a plant-specific program, the NRC staff will assess the adequacy of the plant-specific AMP against the criteria for the 10 AMP program elements that are defined in Section 0 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. *Industrial OE indicates that loss of material due to wear can occur in PWR control rod drive (CRD) head penetration nozzles made of nickel-alloy due to the interactions between the nozzle and the thermal sleeve centering pads of the nozzle (see 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 necessary inspections to confirm that loss of material due to wear does not affect the intended function(s) of these CRD head penetration nozzles, consistent with the CLB.*

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 interaction of the thermal sleeve with the adjacent components (such as CRD head penetration nozzle, drive rod, and penetration housing). For example, loss of material can occur where the thermal sleeve exits from the head penetration nozzle inside the RV (Ref. 30, 38). This type of wear is called thermal sleeve outer diameter wear, which results from the interactions between the thermal sleeve outer surface and the head penetration nozzle. Loss of material can also occur near the bottom of the thermal sleeve due to the interactions between the thermal sleeve inner surface and the drive rod passing though the thermal sleeve (Ref. 38). This type of wear is called thermal sleeve inner-diameter wear. In addition, thermal sleeve flange wear can occur due to the interactions between the bottom side of the thermal sleeve flange and the CRD penetration housing near the top of the thermal sleeve (Ref. 38, 39, 40). 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. *Industry OE indicates that significant loss of material due to wear can occur in ASME Code Class 1, small-bore piping. For example, loss of material can occur in the presence of reflective metal insulation (RMI) and flow-induced vibrations of ASME Code Class 1 small-bore piping. This type of wear is difficult to identify unless the insulation is removed and the outside diameter (OD) of the piping is visually examined for wear marks (Ref. 38 and 39). This type of wear, defined as OD pipe wear, can potentially occur nearly 360 º around the OD of the subject pipe and could significantly reduce the load-bearing capacity of the subject pipe. Therefore, the applicant should perform a further evaluation to confirm the absence of the specific aging effect. If it is determined that the insulation has the potential to cause wear, the licensee may choose to mitigate the loss of material due to wear or alternatively use an existing program for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP. The reviewer should ascertain that the applicant has verified through inspections that OD pipe wear is not an applicable aging effect that needs to be monitored or provide for a periodic inspection program so that significant OD wear of ASME Code Class 1 and 2 small-bore piping is detected prior to the loss of intended function.*

   Plant OE does not indicate OD pipe wear of ASME Code Class 1, small-bore piping within the Reactor Vessel, Internals, and Reactor Coolant System. Despite there being no history of this aging effect, loss of material due to wear will be managed by the External Surfaces Monitoring of Mechanical Components (B.2.3.24) AMP.

3.1.2.2.11 Cracking due to Primary Water Stress Corrosion Cracking

1. *Foreign OE in SGs with a design similar to that of Westinghouse SGs (particularly Model 51) has identified cracks due to primary water stress corrosion cracking (PWSCC) in SG divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry. Cracks have been detected in the stub runner with depths typically about 0.08 inches (in.) (EPRI 3002002850).*

   All but one of these instances of cracking has been detected in divider plate assemblies that are approximately 1.3 in. in thickness. For the cracks in the 1.3-in. thick divider plate assemblies, the cracks tend to be parallel to the divider-plate-to-stub-runner weld (i.e., run horizontally in parallel to the lower surface of the tubesheet). For the one instance of cracking in a divider plate assembly with a thickness greater than 1.3 in., the cracking occurred in a divider plate assembly with a thickness of approximately 2.4 in. near manufacturing marks on the upper end of the stub runner used for locating tubesheet holes. These flaws were estimated to be approximately 0.08-in. deep.

   Although these instances 1 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 should not adversely affect the heat transfer function (as a result of bypass flow) during normal forced flow operation, during natural circulation conditions (assessed in the analyses of various 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, use of the One-Time inspection AMP is not necessary.*

   - *For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the analyses performed by the industry (EPRI 3002002850) are applicable and bounding for the unit, use of the One-Time Inspection AMP is not necessary. Applicants may demonstrate that the industry analyses are applicable and bounding for a site by providing a comparison of plant-specific parameters (e.g., dimensional assumptions for the divider plate, channel head, tube sheet and stub runner; material assumptions for the bottom head and cladding, upper vessel wall, tubesheet, stub runner, divider plate and welds, design, and transient loads) to the values provided in the* *industry analyses. One such method to provide this comparison is to use the checklist provided in the EPRI letter SGMP-IL-16-02.*

- *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, use of the One-Time Inspection AMP is necessary or a rationale should be provided for why such a program is not needed. The One-Time Inspection AMP (in addition to the Water Chemistry and the Steam Generators AMP) should include an inspection that is capable of detecting cracking to verify the effectiveness of the Water Chemistry and Steam Generator AMP and the absence of PWSCC in the divider plate assemblies.*

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and general visual inspections of the channel head interior surfaces (included as part of the Steam Generators AMP). The GALL-SLR Report recommends further evaluation for the use of the One-Time Inspection AMP to confirm the effectiveness of the Water Chemistry and Steam Generator AMPs as described in this section. In place of the one-time inspection AMP, the applicant may provide a rationale to justify why the one-time inspection AMP is not necessary.

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 as follows:*

    - *For units with Alloy 600 SG tubes with permanently approved alternate repair criterion such as C*, F*, H*, or W* for both the hot- and cold-leg side of the SG, the weld is no longer part of the reactor coolant pressure boundary and use of the One-Time Inspection AMP is not necessary.*

    - *For units with Alloy 600 1 steam generator tubes, if there is no permanently approved alternate repair criteria such as C*, F*, H*, or W*, or if the permanent approval applies to only the hot- or cold-leg side of the SG, use of the One-Time Inspection AMP is necessary;*

    - *For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 690 type material, use of the One-Time Inspection AMP is not necessary.*

    - *For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 600 type material, use of the One-Time Inspection AMP is necessary unless the applicant confirms that the industry's analyses for tube-to-tubesheet weld cracking (e.g., chromium content for the tube-to-tubesheet welds is approximately 22 percent and the tubesheet primary face is in compression as discussed in EPRI 3002002850) 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 using the one-time Inspection AMP, the applicant may provide a rationale for why use of the one-time inspection AMP is not necessary.*

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and visual inspections of the steam generator head interior surfaces. Along with the Water Chemistry and Steam Generator AMPs, the One-Time Inspection AMP should be evaluated to confirm the effectiveness of the Water Chemistry and Steam Generators AMPs in certain circumstances. The One-Time Inspection AMP should include an inspection that is capable of detecting cracking to confirm the absence of PWSCC in the tube-to-tubesheet welds. In place of the one-time inspection AMP, the applicant may provide a rationale to justify why the one-time inspection AMP is not necessary.

Not applicable. This further evaluation item is applicable to PWRs only.

3.1.2.2.12 Cracking Due to Irradiation-Assisted Stress Corrosion Cracking

Deleted.

3.1.2.2.13 Loss of Fracture Toughness Due to Neutron Irradiation or Thermal Aging Embrittlement

Deleted.

3.1.2.2.14 Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation

The GALL-SLR Report AMP XI.M9 manages loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR core plate rim hold-down bolts. The issue is applicable to BWR designed light-water reactors that employ rim hold-down bolts as the means for protecting the reactor's core plate from the consequences of lateral movement. The potential for such movement, if left unmanaged, could impact the ability of the reactor to be brought to a safe shutdown condition during an anticipated transient occurrence or during a postulated 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.

The GALL-SLR Report AMP XI.M9 indicates that the inspections in the BWRVIP TR, "BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines (BWRVIP-25)," are used to manage loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR designs with core plate rim hold-down bolts. However, in previous license renewal applications (LRAs), some applicants have identified that the inspection bases for managing loss of preload in BWRVIP-25 may not be capable of gaining access to the rim hold-down bolts or are not sufficient to detect loss of preload on the components. For applicants that have identified this issue in their past LRAs, the applicants either committed to modifying the plant design to install wedges in the core plate designs or to submit an inspection plan, with a supporting core plate rim hold-down bolt *preload analysis for NRC approval at least 2 years prior to entering into the initial period of extended operation for the facility.*

If an existing NRC-approved analysis for the bolts exists in the CLB and conforms to the definition of a TLAA, the applicant should identify the analysis as a TLAA for the SLRA and demonstrate how the analysis is acceptable in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii) (TN4878). 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.

In the HNP CLB, a TLAA is not identified for the core plate holddown bolts. An analysis of the bolts was assessed per the guidance of BWRVIP-25, Revision 1-A and has been approved by the NRC. The analysis determined that these components are appropriately managed through the end of the SPEO utilizing an approved alternate inspection. Therefore, 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 by the BWR Vessel Internals (B.2.3.7) AMP.

3.1.2.2.15 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a highly alkaline environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrate the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (i) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (ii) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (iii) the piping is not potentially exposed to *groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.*

There are no RCS stainless steel or steel piping or piping components within the scope of SLR that are exposed to concrete at HNP. 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: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components; or (iv) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel-alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel-alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel-alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect that requires management for SS and nickel-alloy components if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (ii) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur in the presence of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel-alloy piping and piping components exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect *of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an systems, structures, and components (SSC), GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage loss of material due to pitting or crevice corrosion. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "Detection of Aging Effects" program element in AMP XI.M32.*

The applicant may mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/1 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.

Ambient air at HNP is not subject to a marine atmosphere. The closest highway is US Highway 1 and the use of salt/ash to de-ice roadways is a rare occurrence in the south Georgia environments. A review of the over 30,000 CRs created during the last 10 years of operation 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 and nickel alloy 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 HNP for insulated stainless steel or nickel alloy components for this environment. This indicates 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 (B.2.3.20) 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 10 CFR Part 50, Appendix B Corrective Action Program (CAP).

3.1.2.2.17 Cracking Due to Thermal Fatigue

As addressed in NRC Bulletin 88-08, non-isolable branch lines connected to the reactor coolant system may be subject to unacceptable thermal stress that can cause thermal fatigue cracking and leakage failure (Ref. 44). The NRC Bulletin 88-08 states that, when such piping is identified, actions should be taken to ensure that the piping will not be subject to unacceptable thermal stress.

Industry OE and evaluation indicate that in some branch lines, thermal stratification or mixing cycles can occur due to the interaction between the hot swirl penetration from the reactor coolant system and the cold water in-leakage from a leaking valve (Ref. 45 - 49). In other branch lines, thermal stratification or mixing cycles can result from the interaction of the hot swirl penetration and the cold water in the normally cool, stagnant branch lines without a leaking valve. In addition, cold or hot fluid injections can cause thermal fatigue in the reactor coolant system as indicated in ASME Code Case N-716-1 (Ref. 50). Therefore, cracking due to thermal fatigue can occur due to cyclic stresses from the thermal stratification, mixing or injection cycles.

The industry guidance to manage the thermal fatigue in the PWR branch lines is described in EPRI MRP-146, Revision 2 (Ref. 48). The guidance provides methods for screening and evaluating the susceptibility of non-isolable branch lines to thermal fatigue. The MRP-146, Revision 2 also provides general guidance for monitoring valve in-leakage and thermal stress as needed and performing volumetric examinations on the susceptible locations (e.g., examination areas, volumes, and frequencies). These guidelines continue to be enhanced based on the lessons learned from relevant OE and research activities. The BWRVIP-155, Revision 1 also describes the evaluation of thermal fatigue susceptibility in the branch lines of BWR reactor coolant pressure boundary (Ref. 49).

In addition, the existing aging management at plants may rely on the risk-informed ISI that includes examination of the reactor coolant pressure boundary locations susceptible to thermal fatigue.

As discussed above, cracking due to thermal fatigue can occur in the reactor coolant system. The applicant should perform further evaluation to confirm the adequacy of a plant-specific AMP for management of the aging effect (e.g., adequate selection of susceptible locations for inspections, timely detection of cracks, and preventive action for valve in-leakage as needed). The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP.

There are no branch lines where thermal stratification or mixing cycles can occur due to the interaction between the hot swirl penetration from the reactor coolant system and the cold water in-leakage from a leaking valve. Therefore, cracking due to thermal fatigue cannot occur due to cyclic stresses from the thermal stratification, mixing or injection cycles.

3.1.2.2.18 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP Inspection Quality Materials Branch (IQMB)-1 (Appendix Section A.2 of this SRP-SLR).

QA provisions applicable to SLR are discussed in Appendix B.1.3, Quality Assurance Program and Administrative Controls.

3.1.2.2.19 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix Section A.4, "Operating Experience for Aging Management Programs."

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 Vessel, Internals, and Reactor Coolant System components:

- Section 4.2, *Reactor Vessel Neutron Embrittlement*
- Section 4.3, *Metal Fatigue*

3.1.3 Conclusion

The Reactor Vessel, 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 Vessel, Internals, and Reactor Coolant System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the 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 support skirt and attachment welds 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 reactor coolant pressure boundary 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.				

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, 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.				
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 beltline shell, nozzle, and weld 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.

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, 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.2.2.3) AMPs are used to manage loss of fracture toughness due to neutron irradiation embrittlement of the steel with stainless steel cladding reactor vessel beltline shell, nozzle, and weld 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.
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. HNP does not utilize an isolation condenser. Further evaluation is documented in Section 3.1.2.2.4.2.

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, 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. HNP 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"	No	Not applicable. There are no welded nickel alloy access hole covers in the Reactor Vessel, Internals, and Reactor Coolant System.
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 steel with stainless steel cladding vessel bottom head components 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, 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. HNP 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 CASS Class 1 valve bodies and bonnets exposed to reactor coolant.
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 AMP 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.

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, 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"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The BWR Vessel Internals (B.2.3.7) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking in nickel alloy core shroud plate access hole covers (mechanical covers) exposed to reactor coolant.
3.1-1, 042	Not applicable. This line item only applies to PWRs.				
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) 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 loss of material of stainless steel and nickel alloy reactor vessel internals components exposed to reactor coolant.
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.				

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, 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.				
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.				

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, 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 piping and piping 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 stainless steel bolting exposed to air indoor uncontrolled.
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.				

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, 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.				
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, CASS, and nickel alloy reactor coolant pressure boundary 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.				

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, 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, nozzle safe ends, and attachments and connecting welds 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.				
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.				

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, 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 BWR Vessel ID Attachment Welds (B.2.3.4) and the Water Chemistry (B.2.3.2) AMPs. 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 and nickel alloy vessel shell attachments, attachment welds, and appurtenances 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, 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 and nozzle safe ends exposed to reactor coolant.
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 cladding 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, stainless steel, and nickel alloy piping, piping components, nozzle caps, and spray caps 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, 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.
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"	No	Consistent with NUREG-2191. 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. 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. 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 exception for the Water Chemistry (B.2.3.2) AMP. 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 supports, 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"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. 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.
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.

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, 105	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no HNP reactor coolant pressure boundary piping or piping components exposed to concrete that are subject to external aging effects. Further evaluation is documented in Section 3.1.2.2.15.
3.1-1, 106	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. 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.				

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, 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.
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 and loss of material of reactor coolant system components defined as ASME Section XI Code Class steel, stainless steel, and nickel alloy components 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, 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 HNP stainless steel reactor coolant pressure boundary piping or piping components exposed to concrete that are subject to external aging effects. 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.				
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. The BWR Vessel Internals (B.2.3.7) AMP is used to manage loss of preload for the stainless steel core plate and core plate bolting exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.14.

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, 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. The BWR Vessel Internals (B.2.3.7) AMP is used to manage loss of preload of stainless steel 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 and steel with stainless steel cladding piping and piping components, reactor vessel bottom head, shell, and closure heads 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.				
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, steel with stainless steel cladding, and nickel alloy nozzles, nozzle components, and leak-off lines 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, 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	Not applicable. There are no steel components exposed to treated water that are susceptible to long-term loss of material in the Reactor Vessel, Internals, and Reactor Coolant System.
3.1-1, 134	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not used. Aging effects for thermal insulation are addressed by line 3.3-1, 182.

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. This line item is also applied to reactor vessel flange leak-off lines. The One-Time Inspection (B.2.3.20) AMP and External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs are used to manage loss of material of nickel alloy and stainless steel piping, piping components, reactor vessel flange leak-off lines, and nozzle 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	Consistent with NUREG-2191. There are no aging effects that require management for copper alloy piping and piping components exposed to air indoor uncontrolled. Loss of material in copper alloy piping and piping components exposed to air dry is addressed in item 3.3.1-235.
3.1-1, 139	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, 140	Steel, stainless steel or nickel-alloy piping, piping components exposed to reactor coolant	Cracking due to thermal fatigue	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.17)	Not applicable. There are no steel, stainless steel, or nickel alloy piping and piping components exposed to reactor coolant that are susceptible to thermal fatigue in the Reactor Vessel, Internal, and Reactor Coolant System. Further evaluation is documented in Section 3.1.2.2.17.
3.1-1, 141	Steel, stainless steel or nickel-alloy ASME Code Class 1 small-bore piping, and piping components with reflective metal insulation exposed to air	Loss of material due to wear	Plant-specific or existing aging management program if loss of material is not mitigated	Yes (SRP-SLR Section 3.1.2.2.10)	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 and stainless steel ASME Code Class 1 small-bore piping, and piping components with reflective metal insulation exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.1.2.2.10.

Table 3.1.2-1: Nuclear Boiler 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
Accumulator (MSIV and 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	A
Accumulator (MSIV and steam SRV)	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
Accumulator (MSIV and 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)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.C1.RP-44	3.1-1, 011	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	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)	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)	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 (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

Table 3.1.2-1: Nuclear Boiler 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	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
Condensing chamber	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
Condensing chamber	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.E.E-450b	3.2-1, 107	A
Condensing chamber	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Condensing chamber	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B 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

Table 3.1.2-1: Nuclear Boiler 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
CRD return line welded connection	Pressure boundary	Carbon steel	Reactor coolant (internal)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
CRD return line welded connection	Pressure boundary	Carbon steel	Reactor coolant (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1-1, 110	A
CRD return line welded connection	Pressure boundary	Carbon steel	Reactor coolant (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1-1, 060	A
Flow venturi	Throttle	Cast austenitic stainless steel	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Flow venturi	Throttle	Cast austenitic stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B 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

Table 3.1.2-1: Nuclear Boiler 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	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Orifice	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A
Orifice	Throttle	Stainless steel	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Orifice	Throttle	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A
Piping and piping components	Leakage boundary (spatial)	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	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A

Table 3.1.2-1: Nuclear Boiler 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 and piping components	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.B.E-457	3.2-1, 114	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and 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
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A

Table 3.1.2-1: Nuclear Boiler 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 and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	V.C.E-09	3.2-1, 011	A
Piping and 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 and 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 and 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 and piping components	Pressure boundary	Stainless steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1
Piping and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1
Piping and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.B.E-457	3.2-1, 114	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A

Table 3.1.2-1: Nuclear Boiler 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 and piping components greater than or equal to 4" 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 greater than or equal to 4" NPS (Class 1)	Pressure boundary	Carbon steel	Reactor coolant (internal)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Piping and piping components greater than or equal to 4" NPS (Class 1)	Pressure boundary	Carbon steel	Reactor coolant (internal)	Wall thinning - erosion	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	Carbon steel	Reactor coolant (internal)	Wall thinning - FAC	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	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A

Table 3.1.2-1: Nuclear Boiler 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 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) Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1-1, 097	A B
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) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A
Piping and piping components greater than or equal to 4" NPS (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Wall thinning - erosion	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	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 3.1.2-1: Nuclear Boiler 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 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) Water Chemistry (B.2.3.2) ASME Code Class I Small-Bore Piping (B.2.3.22)	IV.C1.RP-230	3.1-1, 039	A B 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	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A 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 - erosion	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	Carbon steel	Reactor coolant (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1-1, 060	A

Table 3.1.2-1: Nuclear Boiler 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 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
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 Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2) ASME Code Class I Small-Bore Piping (B.2.3.22)	IV.C1.RP-230	3.1-1, 039	A B 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)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A

Table 3.1.2-1: Nuclear Boiler 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 and piping components less than 4" NPS and greater than or equal to 1" NPS (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1-1, 110	A
Piping and piping components with reflective metal insulation	Pressure boundary	Carbon steel	Air – indoor uncontrolled (external)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.A1.R-457	3.1-1, 141	A
Piping and piping components with reflective metal insulation	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.A1.R-457	3.1-1, 141	A
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

Table 3.1.2-1: Nuclear Boiler 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
Safety relief valve pilot body assembly	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Safety relief valve pilot body assembly	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A
Safety relief valve pilot body assembly	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1-1, 110	A
Thermowell	Pressure boundary	Carbon steel	Reactor coolant (internal)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Thermowell	Pressure boundary	Carbon steel	Reactor coolant (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1-1, 110	A
Vacuum breakers	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 3.1.2-1: Nuclear Boiler 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**
Vacuum breakers	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.D2.E-29	3.2-1, 044	A
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	Reactor coolant (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1-1, 110	A
Valve body	Pressure boundary	Carbon steel	Reactor coolant (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1-1, 060	A
Valve body	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Pressure boundary	Copper alloy	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	Air – indoor uncontrolled (external)	None	None	IV.E.R-453	3.1-1, 137	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)	IV.C1.R-452a	3.1-1, 136	A

Table 3.1.2-1: Nuclear Boiler 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.B.E-457	3.2-1, 114	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A
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)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Valve body (Class 1)	Pressure boundary	Carbon steel	Reactor coolant (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1-1, 110	A
Valve body (Class 1)	Pressure boundary	Carbon steel	Reactor coolant (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1-1, 060	A
Valve body (Class 1)	Pressure boundary	Cast austenitic stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A

Table 3.1.2-1: Nuclear Boiler 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 (Class 1)	Pressure boundary	Cast austenitic 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	Cast austenitic stainless steel	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Valve body (Class 1)	Pressure boundary	Cast austenitic stainless steel	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1-1, 097	A B
Valve body (Class 1)	Pressure boundary	Cast austenitic stainless steel	Reactor coolant (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	Cast austenitic stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B 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

Table 3.1.2-1: Nuclear Boiler 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 (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Valve body (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1-1, 097	A B
Valve body (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 Torus Submerged Components Inspection (B.2.4.2) AMP provides supplemental sample-based inspections to manage loss of material of components submerged in the torus.

Table 3.1.2-2: Reactor Recirculation 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 (Class 1)	Mechanical closure	Carbon steel	Air – indoor uncontrolled (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.C1.RP-44	3.1-1, 011	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	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)	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)	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 (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	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

Table 3.1.2-2: Reactor Recirculation 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
Flow nozzle (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
Flow nozzle (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
Flow nozzle (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Flow nozzle (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Heat exchanger (Reactor recirculating pump seal cooler housing)	Heat transfer	Stainless steel	Closed-cycle cooling water >140°F (internal)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-96	3.2-1, 033	C
Heat exchanger (Reactor recirculating pump seal cooler housing)	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-98	3.2-1, 028	C
Heat exchanger (Reactor recirculating pump seal cooler housing)	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-93	3.2-1, 031	A

Table 3.1.2-2: Reactor Recirculation 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 (Reactor recirculating pump seal cooler enclosing cylinder)	Heat transfer	Stainless steel	Reactor coolant (external)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-74	3.2-1, 019	D C
Heat exchanger (Reactor recirculating pump seal cooler enclosing cylinder)	Pressure boundary	Stainless steel	Reactor coolant (external)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	D C
Heat exchanger (Reactor recirculating pump seal cooler enclosing cylinder)	Pressure boundary	Stainless steel	Reactor coolant (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.A.EP-41	3.2-1, 022	B A
Heat exchanger (Reactor recirculating pump seal cooler outer cylinder)	Heat transfer	Stainless steel	Closed-cycle cooling water >140°F (internal)	Reduction of heat transfer	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-96	3.2-1, 033	C
Heat exchanger (Reactor recirculating pump seal cooler outer cylinder)	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-98	3.2-1, 028	C
Heat exchanger (Reactor recirculating pump seal cooler outer cylinder)	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-93	3.2-1, 031	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

Table 3.1.2-2: Reactor Recirculation 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	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	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Orifice	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A
Orifice	Throttle	Stainless steel	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Orifice	Throttle	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A
Piping and piping components	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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

Table 3.1.2-2: Reactor Recirculation 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 and piping components	Leakage boundary (spatial)	Stainless steel	Reactor coolant (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.B.E-457	3.2-1, 114	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Piping and piping components greater than or equal to 4" NPS (Class 1)	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
Piping and piping components greater than or equal to 4" NPS (Class 1)	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1-1, 097	A B
Piping and piping components greater than or equal to 4" NPS (Class 1)	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B 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

Table 3.1.2-2: Reactor Recirculation 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 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) Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1-1, 097	A B
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) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A
Piping and piping components greater than or equal to 4" NPS (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Wall thinning - erosion	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
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

Table 3.1.2-2: Reactor Recirculation 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 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) Water Chemistry (B.2.3.2) ASME Code Class I Small-Bore Piping (B.2.3.22)	IV.C1.RP-230	3.1-1, 039	A B 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)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B 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)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1-1, 110	A
Piping and piping components with reflective metal insulation	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.A1.R-457	3.1-1, 141	A
Pump casing (Recirculation)	Pressure boundary	Cast austenitic 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	Cast austenitic 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

Table 3.1.2-2: Reactor Recirculation 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 (Recirculation)	Pressure boundary	Cast austenitic stainless steel	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1-1, 097	A B
Pump casing (Recirculation)	Pressure boundary	Cast austenitic stainless steel	Reactor coolant (internal)	Loss of fracture toughness	Thermal 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	Cast austenitic stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B 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
Valve body	Leakage boundary (spatial)	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 (spatial)	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	Leakage boundary (spatial)	Stainless steel	Reactor coolant (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.B.E-457	3.2-1, 114	B A

Table 3.1.2-2: Reactor Recirculation 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 (spatial)	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Valve body (Class 1)	Pressure boundary	Cast austenitic 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	Cast austenitic 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	Cast austenitic stainless steel	Reactor coolant (internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Valve body (Class 1)	Pressure boundary	Cast austenitic stainless steel	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1-1, 097	A B
Valve body (Class 1)	Pressure boundary	Cast austenitic stainless steel	Reactor coolant (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

Table 3.1.2-2: Reactor Recirculation 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 (Class 1)	Pressure boundary	Cast austenitic stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B 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) Water Chemistry (B.2.3.2)	IV.E.R-444	3.1-1, 114	A B
Valve body (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1-1, 097	A B
Valve body (Class 1)	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1-1, 079	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 3.1.2-3: 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
Appurtenances	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4) Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1-1, 094	D
Appurtenances	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Appurtenances	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4) Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1-1, 094	D
Appurtenances	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Appurtenances	Structural support	Nickel alloy	Reactor coolant (internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4) Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1-1, 094	D
Appurtenances	Structural support	Nickel alloy	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Appurtenances	Structural support	Stainless steel	Reactor coolant (internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4) Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1-1, 094	D

Table 3.1.2-3: 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
Appurtenances	Structural support	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Attachments and connecting welds	Pressure boundary	Carbon steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-50	3.1-1, 084	D C
Attachments and connecting welds	Pressure boundary	Low alloy steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-50	3.1-1, 084	D C
Attachments and connecting welds	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4) Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1-1, 094	D
Attachments and connecting welds	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Attachments and connecting welds	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4) Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1-1, 094	D
Attachments and connecting welds	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A

Table 3.1.2-3: 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
Attachments and connecting welds	Structural support	Carbon steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-50	3.1-1, 084	D C
Attachments and connecting welds	Structural support	Low alloy steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-50	3.1-1, 084	D C
Attachments and connecting welds	Structural support	Nickel alloy	Reactor coolant (internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4) Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1-1, 094	D
Attachments and connecting welds	Structural support	Nickel alloy	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Attachments and connecting welds	Structural support	Stainless steel	Reactor coolant (internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4) Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1-1, 094	D
Attachments and connecting welds	Structural support	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Bottom head	Pressure boundary	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

Table 3.1.2-3: 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	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) Water Chemistry (B.2.3.2)	IV.A1.RP-371	3.1-1, 030	C D
Bottom head	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Control rod drive return line nozzle	Pressure boundary	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	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-412	3.1-1, 097	A B
Control rod drive return line nozzle	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Control rod drive return line nozzle cap	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (external)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-452b	3.1-1, 136	A

Table 3.1.2-3: 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 cap	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
Control rod drive return line nozzle cap	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-412	3.1-1, 097	A B
Control rod drive return line nozzle cap	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
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) Water Chemistry (B.2.3.2)	IV.A1.R-412	3.1-1, 097	C D
Head spray cap	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Nozzle	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 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	Pressure boundary	Carbon steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-50	3.1-1, 084	B A
Nozzle	Pressure boundary	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
Nozzle	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	C D
Nozzle	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	C D
Nozzle	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
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

Table 3.1.2-3: 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) One-Time Inspection (B.2.3.20)	IV.A1.RP-50	3.1-1, 084	B A
Nozzle safe ends	Pressure boundary	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	C
Nozzle safe ends and flanges	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	C D
Nozzle safe ends and flanges	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
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) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	C D

Table 3.1.2-3: 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 and flanges	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	C D
Nozzle safe ends and flanges	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Penetrations: CRD housing stub tubes, in core monitor housings, instrumentation, SBLC/Core ΔP	Pressure boundary	Nickel alloy	Air – indoor uncontrolled (external)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-452b	3.1-1, 136	C
Penetrations: CRD housing stub tubes, in core monitor housings, instrumentation, SBLC/Core ΔP	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	C
Penetrations: CRD housing stub tubes, in core monitor housings, instrumentation, SBLC/Core ΔP	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cracking	BWR Penetrations (B.2.3.6) Water Chemistry (B.2.3.2)	IV.A1.RP-369	3.1-1, 098	A B

Table 3.1.2-3: 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
Reactor vessel components with fatigue analysis	Pressure boundary	Carbon or low alloy steel with stainless steel cladding	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Reactor vessel components with fatigue analysis	Pressure boundary	Carbon steel	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Reactor vessel components with fatigue analysis	Pressure boundary	Nickel alloy	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Reactor vessel components with fatigue analysis	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Reactor vessel components with fatigue analysis	Structural support	Carbon or low alloy steel with stainless steel cladding	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Reactor vessel components with fatigue analysis	Structural support	Carbon steel	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Reactor vessel components with fatigue analysis	Structural support	Nickel alloy	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Reactor vessel components with fatigue analysis	Structural support	Stainless steel	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Reactor vessel flange leak-off line	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
Reactor vessel flange leak-off line	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

Table 3.1.2-3: 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
Reactor vessel flange leak-off line	Pressure boundary	Stainless steel	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	A B
Reactor vessel flange leak-off line	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Reactor vessel nozzle (feedwater)	Pressure boundary	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
Reactor vessel nozzle (feedwater)	Pressure boundary	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
Reactor vessel nozzle (feedwater)	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	A B
Reactor vessel nozzle (feedwater)	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	A B

Table 3.1.2-3: 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
Reactor vessel nozzle (feedwater)	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Reactor vessel shells, nozzles, and welds in the beltline region of the reactor vessel	Pressure boundary	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
Reactor vessel shells, nozzles, and welds in the beltline region of the reactor vessel	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant and neutron flux (internal)	Loss of fracture toughness	Fluence Monitoring (B.2.2.3) 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	Low alloy steel with stainless steel cladding	Reactor coolant and neutron flux (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Shell and closure heads	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	C
Shell and closure heads	Pressure boundary	Low alloy steel with stainless steel cladding	Neutron flux	Loss of fracture toughness	TLAA - Section 4.2, Reactor Vessel Neutron Embrittlement	IV.A1.R-62	3.1-1, 013	A

Table 3.1.2-3: 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**
Shell and closure heads	Pressure boundary	Low alloy steel with stainless steel cladding	Neutron flux	Loss of fracture toughness	Fluence Monitoring (B.2.2.3) Reactor Vessel Material Surveillance (B.2.3.19)	IV.A1.RP-227	3.1-1, 014	C
Shell and closure heads	Pressure boundary	Low alloy steel with stainless steel cladding	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Support skirt and attachment welds	Structural support	Carbon steel	Air – indoor uncontrolled (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-70	3.1-1, 004	A
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
Thermal sleeves	Direct flow	Stainless steel	Reactor coolant (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1-1, 007	A
Thermal sleeves	Direct flow	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B A
Top head	Pressure boundary	Low alloy 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
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

Table 3.1.2-3: 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 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) Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1-1, 128	A B
Top head instrument nozzle flange	Pressure boundary	Stainless steel	Reactor coolant (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1-1, 085	B 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)	Cracking	Reactor Head Closure Stud Bolting (B.2.3.3)	IV.A1.RP-051	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	TLAA - Section 4.3, Metal Fatigue	IV.A1.RP-201	3.1-1, 001	A

Table 3.1.2-3: 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 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

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 aging management program 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 3.1.2-4: 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
Control rod drive guide tube	Structural support	Stainless steel	Reactor coolant (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1-1, 102	A B
Control rod drive guide tube base	Structural support	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1-1, 102	A B
Control rod drive guide tube base	Structural support	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.R-416	3.1-1, 099	A
Control rod drive housing	Structural support	Stainless steel	Reactor coolant (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1-1, 102	A B
Core plate access hole cover (mechanical design)	Direct flow	Nickel alloy	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-95	3.1-1, 041	A B
Core plate and core plate bolts	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-93	3.1-1, 103	A B
Core plate and core plate bolts	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Loss of preload	BWR Vessel Internals (B.2.3.7)	IV.B1.R-420	3.1-1, 120	A
Core plate DP/SLC line	Direct flow	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-422	3.1-1, 103	A B
Core plate DP/SLC line	Pressure boundary	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-422	3.1-1, 103	A B

Table 3.1.2-4: 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	Direct flow	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-92	3.1-1, 103	A B
Core shroud	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-92	3.1-1, 103	A B
Core spray lines and spargers: piping supports	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1-1, 103	A B
Core spray lines and spargers: spargers, headers, spray rings, pipe brackets, thermal sleeves	Direct flow	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1-1, 103	A B
Core spray lines and spargers: spargers, headers, spray rings, pipe brackets, thermal sleeves	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1-1, 103	A B
Core spray sparger nozzles	Spray	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1-1, 103	A B
Core spray sparger nozzles	Spray	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A

Table 3.1.2-4: 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 sparger nozzles	Spray	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.R-417	3.1-1, 099	A
Core spray sparger nozzles	Spray	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Fuel supports and control rod drive assemblies: orificed fuel support	Structural support	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1-1, 102	C D
Fuel supports and control rod drive assemblies: orificed fuel support	Structural support	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-220	3.1-1, 099	A
Fuel supports and control rod drive assemblies: orificed fuel support	Throttle	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1-1, 102	C D
Fuel supports and control rod drive assemblies: orificed fuel support	Throttle	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-220	3.1-1, 099	A

Table 3.1.2-4: 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**
Instrumentation: intermediate range monitor dry tubes, source range monitor dry tubes, incore flux monitor guide tubes	Pressure boundary	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-105	3.1-1, 103	A B
Instrumentation: intermediate range monitor dry tubes, source range monitor dry tubes, incore flux monitor guide tubes	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-105	3.1-1, 103	A B
Jet pump assemblies: adapter bottom piece, thermal sleeve (Unit 2)	Direct flow	Nickel alloy	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1-1, 103	A B
Jet pump assemblies: castings (diffuser, inlet elbow and nozzle mixer, section adapter, restrainer bracket, and transition piece)	Direct flow	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1-1, 103	A B

Table 3.1.2-4: 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 assemblies: castings (diffuser, inlet elbow and nozzle mixer, section adapter, restrainer bracket, and transition piece)	Direct flow	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-219	3.1-1, 099	A
Jet pump assemblies: holddown beams	Structural support	Nickel alloy	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1-1, 103	A B
Jet pump assemblies: riser brace arms	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1-1, 103	A B
Jet pump assemblies: riser pipe, mixing assembly, diffuser and tailpipe, adapter top piece, sensing line, thermal sleeve (Unit 1)	Direct flow	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1-1, 103	A B
Jet pump assembly holddown beam bolts	Mechanical closure	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1-1, 103	A B
Jet pump assembly holddown beam bolts	Mechanical closure	Stainless steel	Reactor coolant and neutron flux (external)	Loss of preload	BWR Vessel Internals (B.2.3.7)	IV.B1.R-421	3.1-1, 121	A
Jet pump wedge surface	Structural support	Stainless steel	Reactor coolant (external)	Loss of material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-377	3.1-1, 100	A

Table 3.1.2-4: 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 internal components	Direct flow	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Direct flow	Nickel alloy	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A
Reactor vessel internal components	Direct flow	Nickel alloy	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Direct flow	Stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A
Reactor vessel internal components	Direct flow	Stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Mechanical closure	Stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A

Table 3.1.2-4: 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 internal components	Mechanical closure	Stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Pressure boundary	Nickel alloy	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A
Reactor vessel internal components	Pressure boundary	Nickel alloy	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Pressure boundary	Stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A
Reactor vessel internal components	Pressure boundary	Stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B

Table 3.1.2-4: 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 internal components	Structural support	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Structural support	Nickel alloy	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A
Reactor vessel internal components	Structural support	Nickel alloy	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A
Reactor vessel internal components	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B

Table 3.1.2-4: 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 internal components	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Throttle	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Throttle	Nickel alloy	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A
Reactor vessel internal components	Throttle	Nickel alloy	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components	Throttle	Stainless steel	Reactor coolant and neutron flux (external)	Loss of fracture toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1-1, 099	A

Table 3.1.2-4: 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 internal components	Throttle	Stainless steel	Reactor coolant and neutron flux (external)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1-1, 043	A B
Reactor vessel internal components subject to fatigue	Direct flow	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Reactor vessel internal components subject to fatigue	Direct flow	Nickel alloy	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Reactor vessel internal components subject to fatigue	Direct flow	Stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Reactor vessel internal components subject to fatigue	Mechanical closure	Stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Reactor vessel internal components subject to fatigue	Pressure boundary	Stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Reactor vessel internal components subject to fatigue	Structural support	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Reactor vessel internal components subject to fatigue	Structural support	Nickel alloy	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A

Table 3.1.2-4: 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 internal components subject to fatigue	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Reactor vessel internal components subject to fatigue	Throttle	Cast austenitic stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Reactor vessel internal components subject to fatigue	Throttle	Stainless steel	Reactor coolant and neutron flux (external)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1-1, 003	A
Shroud support structure: support plate (Unit 1), support cylinder, support gussets (Unit 1)	Direct flow	Nickel alloy	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-96	3.1-1, 103	A B
Shroud support structure: support plate (Unit 1), support cylinder, support gussets (Unit 1)	Structural support	Nickel alloy	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-96	3.1-1, 103	A B
Shroud support structure: support plate (Unit 2)	Direct flow	Carbon steel with stainless steel cladding	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-92	3.1-1, 103	A B, 1
Shroud support structure: support plate (Unit 2)	Structural support	Carbon steel with stainless steel cladding	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-92	3.1-1, 103	A B, 1

Table 3.1.2-4: 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
Steam dryer	Structural integrity (attached)	Stainless steel	Reactor coolant (external)	Cracking Loss of material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-155	3.1-1, 101	A
Thermal sleeves	Direct flow	Stainless steel	Reactor coolant (internal)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1-1, 103	A B
Top guide	Direct flow	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-98	3.1-1, 103	A B
Top guide	Structural support	Stainless steel	Reactor coolant and neutron flux (external)	Cracking	BWR Vessel Internals (B.2.3.7) Water Chemistry (B.2.3.2)	IV.B1.R-98	3.1-1, 103	A B

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 aging management program 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. The Unit 2 shroud support plate is a unique design which features a cantilevered, extra thick carbon steel plate clad with stainless steel, which does not require legs or gussets for support. The Unit 1 shroud support plate is a more conventional gusseted nickel-alloy design.

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 the systems, which are addressed in this section are described in the indicated sections.

- Core Spray System (Section 2.3.2.1)
- High Pressure Coolant Injection System (Section 2.3.2.2)
- Post LOCA Hydrogen Recombiners System (Unit 2 Only) (Section 2.3.2.3)
- Primary Containment Purge and Inerting System (Section 2.3.2.4)
- Reactor Core Isolation Cooling System (Section 2.3.2.5)
- Residual Heat Removal System (Section 2.3.2.6)
- Standby Gas Treatment System (Section 2.3.2.7)
- Standby Liquid Control System (Section 2.3.2.8)

3.2.2 Results

Table 3.2.2-1, Core Spray System – Summary of Aging Management Evaluation

Table 3.2.2-2, High Pressure Coolant Injection System – Summary of Aging Management Evaluation

Table 3.2.2-3, Post LOCA Hydrogen Recombiners System (Unit 2 Only) – Summary of Aging Management Evaluation

Table 3.2.2-4, Primary Containment Purge and Inerting System – Summary of Aging Management Evaluation

Table 3.2.2-5, Reactor Core Isolation Cooling System – Summary of Aging Management Evaluation

Table 3.2.2-6, Residual Heat Removal System – Summary of Aging Management Evaluation

Table 3.2.2-7, Standby Gas Treatment System – Summary of Aging Management Evaluation

Table 3.2.2-8, Standby Liquid Control System – Summary of Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.2.2.1.1 Core Spray System

Materials

The materials of construction for the CS system components are:

- Carbon steel
- Cast austenitic stainless steel
- Glass
- Stainless steel

Environments

The CS system components are exposed to the following environments:

- Air – indoor uncontrolled
- Lubricating oil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the CS system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the CS 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)
- Torus Submerged Components Inspection (B.2.4.2)
- Water Chemistry (B.2.3.2)

3.2.2.1.2 High Pressure Coolant Injection System

Materials

The materials of construction for the HPCI system components are:

- Carbon steel
- Copper alloy
- Copper alloy with greater than 15% Zn
- Glass
- Stainless steel

Environments

The HPCI system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Lubricating oil
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the HPCI 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 HPCI 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)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Torus Submerged Components Inspection (B.2.4.2)
- Water Chemistry (B.2.3.2)

3.2.2.1.3 Post LOCA Hydrogen Recombiners System (Unit 2 Only)

Materials

The materials of construction for the post LOCA hydrogen recombiners system (Unit 2 only) components are:

- Carbon steel

Environments

The post LOCA hydrogen recombiners system (Unit 2 only) components are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects associated with the post LOCA hydrogen recombiners system (Unit 2 only) require management:

- Loss of material

Aging Management Programs

The following AMPs manage the aging effects for the post LOCA hydrogen recombiners system (Unit 2 only) components:

- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)

3.2.2.1.4 Primary Containment Purge and Inerting System

Materials

The materials of construction for the primary containment purge and inerting systems are:

- Aluminum
- Carbon steel
- Stainless steel

Environments

The primary containment purge and inerting systems components are exposed to the following environments:

- Air - indoor uncontrolled
- Gas
- Liquid nitrogen
- Treated water
- Vacuum

Aging Effects Requiring Management

The following aging effects associated with the primary containment purge and inerting systems 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 primary containment purge and inerting 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)
- One-Time Inspection (B.2.3.20)
- Torus Submerged Components Inspection (B.2.4.2)
- Water Chemistry (B.2.3.2)

3.2.2.1.5 Reactor Core Isolation Cooling System

Materials

The materials of construction for the RCIC system components are:

- Carbon steel
- Cast austenitic stainless steel
- Copper alloy
- Copper alloy with greater than 15% Zn
- Glass
- Stainless steel

Environments

The RCIC system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Lubricating oil
- Treated water
- Treated water > 140°F

Aging Effects Requiring Management

The following aging effects associated with the RCIC system require aging management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning – erosion
- Wall thinning – FAC

Aging Management Programs

The following AMPs manage the aging effects for the RCIC 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)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Torus Submerged Components Inspection (B.2.4.2)
- Water Chemistry (B.2.3.2)

3.2.2.1.6 Residual Heat Removal System

Materials

The materials of construction for the RHR system components are:

- Carbon steel
- Carbon steel with stainless steel cladding
- Cast austenitic stainless steel
- Copper alloy with greater than 15% Zn
- Glass
- Nickel alloy
- Stainless steel

Environments

The RHR system components are exposed to the following environments:

- Air – indoor uncontrolled
- Lubricating oil
- Raw water
- Soil
- 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
- Reduction of heat transfer
- Wall thinning – erosion

Aging Management Programs

The following AMPs manage the aging effects for the RHR 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)

- RHR Heat Exchanger Augmented Inspection (B.2.4.1)
- Selective Leaching (B.2.3.21)
- Torus Submerged Components Inspection (B.2.4.2)
- Water Chemistry (B.2.3.2)

3.2.2.1.7 Standby Gas Treatment System

Materials

The materials of construction for the SBGT system components are:

- Carbon steel
- Copper alloy with greater than 15% Zn
- Galvanized steel
- Gray cast iron
- Stainless steel

Environments

The SBGT system components are exposed to the following environments:

- Air – indoor uncontrolled
- Soil
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the SBGT system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the SBGT 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)

3.2.2.1.8 Standby Liquid Control System

Materials

The materials of construction for the SBLC system components are:

- Carbon steel
- Glass

- Stainless steel

Environments

The SBLC system components are exposed to the following environments:

- Air – indoor uncontrolled
- Sodium pentaborate solution
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the SBLC system require management:

- Cracking
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the SBLC system components:

- Bolting Integrity (B.2.3.10)
- 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)
- Water Chemistry (B.2.3.2)

3.2.2.2 Further Evaluation of Aging Management as Recommended by GALL-SLR

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 TLAAs, as defined in 10 CFR 54.3 (TN4878). The TLAAs are required to be evaluated in accordance with 10 CFR 54.21I(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 for applicable ESF components is an aging effect evaluated as a TLAA in Section 4.3, Metal Fatigue.

3.2.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel-alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components; or (iv) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel-alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or into the surfaces of other components below the component. For outdoor insulated SS and nickel-alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel-alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect that requires management for SS and nickel-alloy components if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion, and (ii) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur in the presence of a source of moisture or halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel-alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of SSCs, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (i) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, a one-time inspection would be conducted between the 50th and 60th year of operation, as recommended by the "Detection of Aging Effects" program element in AMP XI.M32.

The applicant may mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive or corrosive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain moisture or halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Ambient air at HNP is not subject to a marine atmosphere. The closest highway is US Highway 1 and the use of salt/ash to de-ice roadways is a rare occurrence in the south Georgia environments. A review of the over 30,000 CRs created during the last 10 years of operation 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 10 CFR Part 50, Appendix B, 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 remains in standby. The wetting and drying of these components can accelerate corrosion in the system and lead to flow blockage from an accumulation of corrosion products. Aging effects sufficient to result in a loss of intended function are not anticipated if: (i) the applicant identifies those portions of the system that are normally dry but subject to periodic wetting; (ii) plant-specific procedures exist to drain the normally dry portions that have been wetted during normal plant operation or inadvertently; (iii) the plant-specific configuration of the drains and piping allow sufficient draining to empty the normally dry pipe; (iv) plant-specific OE has not revealed loss of material or flow blockage due to fouling; and (v) a one-time inspection is conducted to verify that loss of material or flow blockage due to fouling has not occurred. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to conduct the one-time inspections. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage loss of material due to general corrosion and flow blockage due to fouling when the above conditions are not met.

This item evaluates loss of material and flow blockage of metallic drywell and suppression chamber spray nozzles exposed to air-indoor uncontrolled. The drywell and suppression chamber spray nozzles within the RHR are copper alloy with greater than 15 percent zinc and are exposed to an air-indoor uncontrolled 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 due to general corrosion and flow blockage due to fouling are applicable aging effects for the spray nozzles since the upstream piping is carbon steel.

Plant-specific OE has revealed minor corrosion build up and flow blockage of the drywell spray nozzles. In these cases, the nozzles were cleaned to clear the rust and restore flow. Since plant-specific OE indicates the potential for loss of material and flow blockage to occur, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be implemented to manage these aging effects for the drywell and suppression chamber spray nozzles. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B, CAP. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is described in Section B.2.3.24.

3.2.2.2.4 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to SCC could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components, or (iv) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation to leach onto the component surface or into the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion compromising the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. The SCC in SS components is not an aging effect that requires management if: (i) plant-specific OE does not reveal a history of SCC and (ii) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur due to the presence of a source of moisture and/or 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 cracking due to SCC: (i) the GALL-SLR Report AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” for tanks; (ii) the GALL-SLR Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” for external surfaces of piping and piping components; (iii) the GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” for underground piping, piping components and tanks; and (iv) the GALL-SLR Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the “Detection of Aging Effects” program element in AMP XI.M32.

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Ambient air at HNP is not subject to a marine atmosphere. The closest highway is US Highway 1 and the use of salt/ash to de-ice roadways is a rare occurrence in the south Georgia environments. A review of the over 30,000 CRs created during the last 10 years of operation 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 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 (B.2.3.20) 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 10 CFR Part 50, Appendix B, CAP.

3.2.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix Section A.2 of this SRP-SLR).

Quality Assurance 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 Section A.4, "Operating Experience for Aging Management Programs."

The Operating Experience 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: (i) a 10 year search of plant-specific OE reveals the aging *effect has occurred in three or more refueling outage cycles; or (ii) a 5 year search of plant-specific OE revealing that the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant-specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).*

The GALL-SLR Report recommends that the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to assure any recurring aging effect(s) are adequately managed. Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (i) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (ii) the basis for the adequacy of augmented or lack of augmented inspections, (iii) the trend of which parameters will be followed as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (iv) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (v) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant-specific OE, two instances of a 360º 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold was exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the CLB intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in environments other than raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

HNP OE over the past 10 years indicates that recurring internal corrosion exists for steel components that use raw water from the Altamaha River; therefore, recurring internal corrosion is an applicable aging effect at HNP.

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is a new AMP and will address recurring internal corrosion by having measures in place to inspect additional samples for recurring degradation to ensure that corrective actions are appropriately addressing the associated causes. For ongoing degradation mechanisms (e.g., MIC and erosion) 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 will be conducted if one of the inspections does not meet acceptance criteria. The number of inspections will be increased in accordance with the CAP; however, no fewer than five additional inspections will be conducted for each inspection that does not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination are inspected, whichever is less.

Therefore, there is no need to augment the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP because it already includes specific measures to detect and manage 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 SLR, acceptance criteria for this further evaluation are provided for demonstrating that the specific material is not susceptible to SCC or the ambient environment is not aggressive in nature. Cracking due to SCC is an aging effect which requires management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

<u>Susceptible Material</u>: If the material is not susceptible to SCC, then cracking is not an aging effect which requires management. The microstructure of an aluminum alloy, of which alloy composition is only one factor that determines whether the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper type, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the as fabricated (F), solution heat-treated (W), annealed (O)x, thermally treated (T)3x, T4x, or T6x temper;*
- *5xxx series alloys with a magnesium content of 3.5 weight percent (wt%) or greater;*
- *6xxx series alloys in the F temper;*
- *7xxx series alloys in the F, T5x, or T6x temper;*
- *2xx.x and 7xx.x series alloys;*
- *3xx.x series alloys that contain copper; and*
- *5xx.x series alloys with a magnesium content of greater than 8 wt%.*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC *when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, 6063-T6, and 5454-x, respectively. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, and3.2-7orduct form. For tempers not addressed above, the basis used to determine that the alloy is not susceptible and technical information substantiating the basis is added to the SLRA.*

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect which requires management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys include the presence of aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation layer or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, halide concentrations sufficient to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. The GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks, which are buried or underground. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings or 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 susceptible to cracking 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 highly alkaline environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the highly alkaline environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrate the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (i) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (ii) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (iii) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Loss of material due to crevice or pitting corrosion and cracking due to SCC for stainless steel ESF components exposed to concrete are applicable aging effects. Consistent with the recommendation of GALL-SLR, the Buried and Underground Piping and Tanks AMP (B.2.3.27) will be used to manage the aging effects of loss of material and cracking in stainless steel exposed to concrete.

3.2.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air greatly depends on the geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect that requires management for aluminum alloys if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (ii) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. Alternatively, loss of material due to pitting and crevice corrosion need not be managed if the type of aluminum is not susceptible to cracking and plant-specific OE does not reveal any issues related to loss of material due to pitting or crevice corrosion. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur in the presence of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of 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.*

The applicant may mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL- SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Not applicable. There are no aluminum components susceptible to loss of material in the ESF Systems.

3.2.2.2.11 Loss of Material Due to Wear

Industry OE indicates that significant loss of material due to wear can occur in ASME Code Class 2, small-bore piping. For example, loss of material can occur in the presence of RMI, and flow-induced vibrations of ASME Code Class 2 small-bore piping. This type of wear is difficult to identify unless the insulation is removed and the OD of the piping is visually examined for wear marks (Ref. 8). This type of wear is called OD pipe wear, and in some instances can be potentially near 360º around the OD of the subject pipe and could significantly reduce the load-bearing capacity of the subject pipe. Therefore, the applicant should perform further evaluation to confirm the absence of the specific aging effect. If moderate or no degradation is evident, but it is determined that the insulation is such that it has the potential to cause wear, the applicant may choose to mitigate the loss of material due to wear or alternatively use an existing program for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP. The reviewer should make sure that the that the applicant has verified through inspections that OD pipe wear is not an applicable aging effect that needs to be monitored or provide for periodic inspection program so that significant OD loss of material is detected prior to loss of intended function.

There is no Class 2 piping with reflective metal insulation in the ESF Systems. Therefore loss of material due to wear from reflective metal insulation is not applicable.

3.2.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the ESF System components:

- Section 4.3, *Metal Fatigue*

3.2.3 Conclusion

The ESF 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 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 ESF 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 3.2-1: 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. 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. 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 and air outdoor. Further evaluation is documented in Section 3.2.2.2.2.
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 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 copper alloy with >15% Zn drywell and suppression chamber spray system nozzles exposed to air indoor uncontrolled. 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. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of stainless steel and CASS piping, piping components, and heat exchanger components exposed to air indoor uncontrolled or air outdoor. This line item is also applied to components within the Reactor Vessel, Internals, and Reactor Coolant System. 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. This line item is also applied to components within the Reactor Vessel, Internals, and Reactor Coolant System and the Auxiliary Systems.
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 or air outdoor environment.

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, 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) and plant-specific Torus Submerged Components Inspection (B.2.4.2) AMPs are used to manage loss of preload of metallic closure bolting in air indoor uncontrolled, air outdoor, and treated water environments.
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. The Water Chemistry (B.2.3.2), One-Time Inspection (B.2.3.20), plant-specific Torus Submerged Components Inspection (B.2.4.2), and plant-specific RHR Heat Exchanger Augmented Inspection (B.2.4.1) AMPs are used to manage loss of material of steel piping, piping components, and heat exchangers exposed to treated water. This line item is also applied to components within the Reactor Vessel, Internals, and Reactor Coolant System.
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.

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, 019	Stainless steel, nickel alloy heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," 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), One-Time Inspection (B.2.3.20), and plant-specific RHR Heat Exchanger Augmented Inspection (B.2.4.1) AMPs are used to manage reduction of heat transfer of stainless steel heat exchanger tubes exposed to treated water. This line item is also applied to components within the Reactor Vessel, Internals, and Reactor Coolant System.
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), One-Time Inspection (B.2.3.20), plant-specific Torus Submerged Components Inspection (B.2.4.2), and plant-specific RHR Heat Exchanger Augmented Inspection (B.2.4.1) AMPs are used to manage loss of material of stainless steel, nickel alloy, and steel with stainless steel cladding heat exchanger components, piping, and piping components exposed to treated water. This line item is also applied to components within the Reactor Vessel, Internals, and Reactor Coolant System.
3.2-1, 023	Steel heat exchanger components, piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.3.11) and plant-specific RHR Heat Exchanger Augmented Inspection (B.2.4.1) AMPs are used to manage loss of material and flow blockage of steel heat exchanger components exposed to raw water.
3.2-1, 024	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, 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	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.3.11) and plant-specific RHR Heat Exchanger Augmented Inspection (B.2.4.1) AMPs are used to manage loss of material and flow blockage of stainless steel and steel with stainless steel cladding heat exchanger components exposed to raw water. This line item is also applied to components within the Auxiliary Systems.
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	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.3.11) and plant-specific RHR Heat Exchanger Augmented Inspection (B.2.4.1) AMPs are used to manage reduction of heat transfer in stainless steel heat exchanger tubes exposed to raw water. This line item is also applied to components within the Auxiliary 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, 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	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage cracking in stainless steel heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F). This line item is applied to components within the Reactor Vessel, Internals, and Reactor Coolant System.
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 exposed to closed-cycle cooling water in the ESF Systems.
3.2-1, 030	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no steel heat exchanger components exposed to closed-cycle cooling water in 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, 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 recirculation pump seal cooler heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F). This line item is applied to components within the Reactor Vessel, Internals, and Reactor Coolant System.
3.2-1, 032	Copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no copper alloy heat exchanger components, piping, or piping components 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, 033	Copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage reduction in heat transfer of stainless steel heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F). This line item is applied to components within the Reactor Vessel, Internals, and Reactor Coolant System.
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 with >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, malleable iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no gray cast iron, ductile iron, or malleable iron piping, or piping components exposed to soil 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, 038	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no elastomer components exposed to air in the ESF Systems.
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 and air outdoor.
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	Not applicable. There are no elastomer components exposed to air 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, 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. 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, ducting, and ducting components exposed to indoor air uncontrolled. This line item is also applied to components within the Reactor Vessel, Internals, and Reactor Coolant System and the Auxiliary Systems.
3.2-1, 045	Not applicable. This line item only applies to PWRs.				
3.2-1, 046	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel piping or piping components exposed to condensation in the ESF Systems. The air indoor uncontrolled environment is used in lieu of the condensation environment.
3.2-1, 047	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, 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)	Not applicable. There are no stainless steel or nickel alloy components exposed to condensation in the ESF Systems. The air indoor uncontrolled environment is used in lieu of the condensation environment. 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.
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. 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.

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, 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 with exception for the Buried and Underground Piping and Tanks (B.2.3.27) AMP. 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.
3.2-1, 053	Stainless steel, nickel alloy piping, piping components, tanks, exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191 with exception for the Buried and Underground Piping and Tanks (B.2.3.27) AMP. 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 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 do 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 that are subject to external aging effects. 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 exposed to air or condensation that are susceptible to cracking 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 heat exchanger components, piping, and piping components exposed to air indoor uncontrolled. Cracking in copper alloy piping and piping components exposed to air indoor uncontrolled is addressed in items 3.2-1, 071, 3.3-1, 132, and 3.4-1, 106.
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	Consistent with NUREG-2191. There are no aging effects that require management for galvanized steel ducting and ducting components exposed to air indoor controlled.
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 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, piping components, and heat exchanger tubes exposed to gas, liquid nitrogen, or vacuum.
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 or vacuum.
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. This line item is also applied to components within the Reactor Vessel, Internals, and Reactor Coolant System.

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, 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)	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 in metallic piping and piping components exposed to raw water. Further evaluation is documented in Section 3.2.2.2.7.
3.2-1, 067	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	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.

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, 069	Insulated steel piping, piping components, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no insulated steel piping, piping components, or tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP exposed to air indoor uncontrolled within the ESF Systems.
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.
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking of copper alloy (>15% Zn) piping and piping components 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, 072	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, condensation	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191. 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 in internally coated carbon steel piping components and heat exchanger components exposed to raw water or sodium pentaborate solution.
3.2-1, 073	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, condensation	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP is not used to manage loss of material 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, 074	Gray cast iron, ductile iron, malleable iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. There are no gray cast iron, ductile iron, or malleable 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 closure 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 with exception for the Buried and Underground Piping and Tanks (B.2.3.27) AMP. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage cracking in stainless steel and steel piping, 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, 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 or air outdoor.
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. 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 aluminum heat exchanger components exposed to air indoor uncontrolled.
3.2-1, 087	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not used. Aging effects for thermal insulation are addressed by line 3.3-1, 182.

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, 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 raw water.
3.2-1, 091	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not used. Stainless steel piping and piping components exposed to concrete are addressed by item 3.2-1, 053. 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	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 for steel and stainless steel piping or piping components exposed to raw water not covered by NRC GL 89-13.
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.

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, 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 used. Loss of material of stainless steel tanks exposed to air indoor uncontrolled is addressed by item 3.2-1, 004. Further evaluation is documented in Section 3.2.2.2.2.
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.

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, 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 or piping components 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 (B.2.3.17) 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 indoor uncontrolled. This line item is applied to components within the Reactor Vessel, Internals, and Reactor Coolant System. 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)	Not used. Cracking of insulated stainless steel piping and piping components exposed to air indoor uncontrolled is addressed by item 3.2-1, 007. 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 aluminum piping or piping components exposed to air or condensation that are susceptible to cracking 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, 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 or piping components in the ESF Systems. Further evaluation is documented in Section 3.2.2.2.8.
3.2-1, 111	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no underground aluminum piping or piping components 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 or piping components 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, 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 piping and piping components exposed to treated water >60°C (>140°F). This line item is also applied to components within the Reactor Vessel, Internals, and Reactor Coolant System.
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.
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.

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, 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.
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 aluminum piping or piping components exposed to air or condensation that are susceptible to cracking 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.

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, 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, or piping components exposed to raw water or waste water in the ESF Systems. Further evaluation is documented in Section 3.2.2.2.10.
3.2-1, 122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no elastomer components exposed to air in the ESF Systems.
3.2-1, 123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer components exposed to air in the ESF Systems.
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 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, 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.
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.

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, 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, 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.
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	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP is used to manage blistering, cracking, hardening, loss of material, and loss of strength of polymeric components exposed to air.
3.2-1, 135	Steel, stainless steel, nickel alloy Class 2, small-bore piping and piping components with reflective metal insulation exposed to air	Loss of material due to wear	Plant-specific or existing aging management program if loss of material is not mitigated	Yes (SRP-SLR Section 3.2.2.2.11)	Not applicable. There are no steel, stainless steel, or nickel alloy Class 2, small-bore piping and piping components with reflective metal insulation exposed to air in the ESF Systems. Further evaluation is documented in Section 3.2.2.2.11.

Table 3.2.2-1: Core Spray 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 steel	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 steel	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	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Bolting (Closure)	Mechanical closure	Stainless steel	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	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	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	Treated water (external)	Loss of preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2-1, 015	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	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A

Table 3.2.2-1: Core Spray 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	Throttle	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and 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 and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A

Table 3.2.2-1: Core Spray 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 and 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 and 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 and piping components	Pressure boundary	Stainless steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1
Piping and piping components	Pressure boundary	Stainless steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1
Piping and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping elements	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (external)	None	None	V.F.EP-15	3.2-1, 060	A
Piping elements	Leakage boundary (spatial)	Glass	Treated water (internal)	None	None	V.F.EP-29	3.2-1, 060	A

Table 3.2.2-1: Core Spray 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 (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)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Pump casing (Jockey)	Pressure boundary	Cast austenitic 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 (Jockey)	Pressure boundary	Cast austenitic 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
Pump casing (Jockey)	Pressure boundary	Cast austenitic stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Strainer (element)	Filter	Stainless steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1

Table 3.2.2-1: Core Spray 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	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Strainer (element)	Filter	Stainless steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1
Strainer (element)	Filter	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	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

Table 3.2.2-1: Core Spray 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	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Pressure boundary	Cast austenitic 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	Cast austenitic 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	Cast austenitic stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 Torus Submerged Components Inspection (B.2.4.2) AMP provides supplemental sample-based inspections to manage loss of material of components submerged in the torus.

Table 3.2.2-2: High Pressure Coolant Injection 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**
Blower housing (HPCI vacuum pump)	Leakage boundary (spatial)	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 vacuum pump)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Bolting (Closure)	Mechanical closure	Carbon steel	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 steel	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)	V.E.E-421	3.2-1, 079	A
Bolting (Closure)	Mechanical closure	Stainless steel	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	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 – outdoor (external)	Cracking	Bolting Integrity (B.2.3.10)	V.E.E-421	3.2-1, 079	A
Bolting (Closure)	Mechanical closure	Stainless steel	Air – outdoor (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	Air – outdoor (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	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	Treated water (external)	Loss of preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2-1, 015	A

Table 3.2.2-2: High Pressure Coolant Injection 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 (Unit 1 lube oil cooler) channel head	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 (Unit 1 lube oil cooler) channel head	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4-1, 015	B A
Heat exchanger (Unit 1 lube oil cooler) shell	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 (Unit 1 lube oil cooler) shell	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.E-473	3.2-1, 130	A
Heat exchanger (Unit 1 lube oil cooler) tubes	Heat transfer	Copper alloy with greater than 15% Zn	Lubricating oil (external)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-78	3.2-1, 051	A
Heat exchanger (Unit 1 lube oil cooler) tubes	Heat transfer	Copper alloy with greater than 15% Zn	Treated water (internal)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-100	3.4-1, 018	B A

Table 3.2.2-2: High Pressure Coolant Injection 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 (Unit 1 lube oil cooler) tubes	Pressure boundary	Copper alloy with greater than 15% Zn	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2-1, 050	C
Heat exchanger (Unit 1 lube oil cooler) tubes	Pressure boundary	Copper alloy with greater than 15% Zn	Treated water (internal)	Loss of material	Selective Leaching (B.2.3.21)	V.D2.EP-37	3.2-1, 034	A
Heat exchanger (Unit 1 lube oil cooler) tubes	Pressure boundary	Copper alloy with greater than 15% Zn	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3-1, 022	D C
Heat exchanger (Unit 1 lube oil cooler) tubesheet	Pressure boundary	Carbon steel	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.E-473	3.2-1, 130	A
Heat exchanger (Unit 1 lube oil cooler) tubesheet	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4-1, 015	B A
Heat exchanger (Unit 2 lube oil cooler) channel head	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	V.F.EP-10	3.2-1, 057	C

Table 3.2.2-2: High Pressure Coolant Injection 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 (Unit 2 lube oil cooler) channel head	Pressure boundary	Copper alloy	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3-1, 022	D C
Heat exchanger (Unit 2 lube oil cooler) shell	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Heat exchanger (Unit 2 lube oil cooler) shell	Pressure boundary	Copper alloy with greater than 15% Zn	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2-1, 050	C
Heat exchanger (Unit 2 lube oil cooler) tubes	Heat transfer	Copper alloy with greater than 15% Zn	Lubricating oil (external)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-78	3.2-1, 051	A
Heat exchanger (Unit 2 lube oil cooler) tubes	Heat transfer	Copper alloy with greater than 15% Zn	Treated water (internal)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-100	3.4-1, 018	B A
Heat exchanger (Unit 2 lube oil cooler) tubes	Pressure boundary	Copper alloy with greater than 15% Zn	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) 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 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 (Unit 2 lube oil cooler) tubes	Pressure boundary	Copper alloy with greater than 15% Zn	Treated water (internal)	Loss of material	Selective Leaching (B.2.3.21)	V.D2.EP-37	3.2-1, 034	A
Heat exchanger (Unit 2 lube oil cooler) tubes	Pressure boundary	Copper alloy with greater than 15% Zn	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3-1, 022	D C
Heat exchanger (Unit 2 lube oil cooler) tubesheet	Pressure boundary	Copper alloy	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2-1, 050	C
Heat exchanger (Unit 2 lube oil cooler) tubesheet	Pressure boundary	Copper alloy	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3-1, 022	D C
Hose	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
Hose	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
Hose	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B 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

Table 3.2.2-2: High Pressure Coolant Injection 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	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	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Orifice	Throttle	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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 3.2.2-2: High Pressure Coolant Injection 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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and 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 and 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.D2.E-29	3.2-1, 044	A
Piping and piping components	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-60	3.2-1, 016	E, 1
Piping and piping components	Pressure boundary	Carbon steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-60	3.2-1, 016	E, 1

Table 3.2.2-2: High Pressure Coolant Injection 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 and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and 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 and 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 and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Piping and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Concrete (external)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	V.E.E-420	3.2-1, 078	B
Piping and piping components	Pressure boundary	Stainless steel	Concrete (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	V.E.EP-72	3.2-1, 053	B
Piping and piping components	Pressure boundary	Stainless steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.A.SP-95	3.4-1, 044	A
Piping and piping components	Pressure boundary	Stainless steel	Soil (external)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	V.E.E-420	3.2-1, 078	B

Table 3.2.2-2: High Pressure Coolant Injection 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 and piping components	Pressure boundary	Stainless steel	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	V.E.EP-72	3.2-1, 053	B
Piping and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping elements	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (external)	None	None	V.F.EP-15	3.2-1, 060	A
Piping elements	Leakage boundary (spatial)	Glass	Treated water (internal)	None	None	V.F.EP-29	3.2-1, 060	A
Pump casing (HPCI condenser pump)	Leakage boundary (spatial)	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 condenser pump)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Pump casing (HPCI main booster 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 (HPCI main booster pump)	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A

Table 3.2.2-2: High Pressure Coolant Injection 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 (HPCI main 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 (HPCI main pump)	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Pump casing (HPCI turbine aux oil 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 (HPCI turbine aux oil pump)	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A
Pump casing (HPCI turbine main oil 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 (HPCI turbine main oil pump)	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A
Strainer (element)	Filter	Stainless steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1

Table 3.2.2-2: High Pressure Coolant Injection 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	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Strainer (element)	Filter	Stainless steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1
Strainer (element)	Filter	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Tank (HPCI barometric condenser)	Leakage boundary (spatial)	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
Tank (HPCI barometric condenser)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4-1, 012	B A
Tank (HPCI vacuum)	Leakage boundary (spatial)	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
Tank (HPCI vacuum)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4-1, 012	B A

Table 3.2.2-2: High Pressure Coolant Injection 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**
Thermowell	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
Thermowell	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Turbine housing	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 housing	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 3.2.2-2: High Pressure Coolant Injection 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 (spatial)	Stainless steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2-1, 050	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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B 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	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2-1, 050	A
Valve body	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 Torus Submerged Components Inspection (B.2.4.2) AMP provides supplemental sample-based inspections to manage loss of material of components submerged in the torus.

Table 3.2.2-3: Post LOCA Hydrogen Recombiners System (Unit 2 Only) – Summary 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	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 and 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.A.E-29	3.2-1, 044	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.2.2-4: Primary Containment Purge and Inerting 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 steel	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 steel	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)	V.E.E-421	3.2-1, 079	A
Bolting (Closure)	Mechanical closure	Stainless steel	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2-1, 015	A
Heat exchanger (Pressure buildup coil) 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 (Pressure buildup coil) tubes	Heat transfer	Stainless steel	Gas (internal)	None	None	V.F.EP-22	3.2-1, 063	C
Heat exchanger (Pressure buildup coil) tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.A.EP-103b	3.2-1, 007	A
Heat exchanger (Pressure buildup coil) tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Heat exchanger (Pressure buildup coil) tubes	Pressure boundary	Stainless steel	Gas (internal)	None	None	V.F.EP-22	3.2-1, 063	C

Table 3.2.2-4: Primary Containment Purge and Inerting 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 (Vaporizer) fins	Heat transfer	Aluminum	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 (Vaporizer) tubes	Heat transfer	Stainless steel	Gas (internal)	None	None	V.F.EP-22	3.2-1, 063	C
Heat exchanger (Vaporizer) tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.A.EP-103b	3.2-1, 007	A
Heat exchanger (Vaporizer) tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.A.EP-103b	3.2-1, 007	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.B.EP-103b	3.2-1, 007	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Piping and 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

Table 3.2.2-4: Primary Containment Purge and Inerting 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 and 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.A.E-29	3.2-1, 044	A
Piping and piping components	Pressure boundary	Carbon steel	Gas (internal)	None	None	V.F.EP-7	3.2-1, 064	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-60	3.2-1, 016	E, 2
Piping and piping components	Pressure boundary	Carbon steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-60	3.2-1, 016	E, 2
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.B.EP-103b	3.2-1, 007	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.B.EP-103b	3.2-1, 007	A

Table 3.2.2-4: Primary Containment Purge and Inerting 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 and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Gas (internal)	None	None	V.F.EP-22	3.2-1, 063	A
Rupture disk	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.B.EP-103b	3.2-1, 007	A
Rupture disk	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Rupture disk	Pressure boundary	Stainless steel	Gas (internal)	None	None	V.F.EP-22	3.2-1, 063	A
Tank (Liquid nitrogen storage)	Pressure boundary	Stainless steel	Liquid nitrogen (internal)	None	None	V.F.EP-22	3.2-1, 063	G, 1
Tank (Liquid nitrogen storage)	Pressure boundary	Stainless steel	Vacuum (external)	None	None	V.F.EP-22	3.2-1, 063	G, 1
Tank (Nitrogen tank jacket)	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
Tank (Nitrogen tank jacket)	Structural integrity (attached)	Carbon steel	Vacuum (internal)	None	None	V.F.EP-7	3.2-1, 064	G, 1
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

Table 3.2.2-4: Primary Containment Purge and Inerting 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	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
Valve body	Pressure boundary	Carbon steel	Gas (internal)	None	None	V.F.EP-7	3.2-1, 064	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.A.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.B.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.B.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.B.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

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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.

G. Environment not in NUREG-2191 for this component and material.

Plant Specific Notes

1. There are no contaminants or moisture in these environments, so there are no applicable aging effects that need to be managed.
2. The Torus Submerged Components Inspection (B.2.4.2) AMP provides supplemental sample-based inspections to manage loss of material of components submerged in the torus.

Table 3.2.2-5: Reactor Core Isolation Cooling 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 steel	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 steel	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)	V.E.E-421	3.2-1, 079	A
Bolting (Closure)	Mechanical closure	Stainless steel	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	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	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	Treated water (external)	Loss of preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2-1, 015	A
Heat exchanger (RCIC lube oil cooler) channel head	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	V.F.EP-10	3.2-1, 057	A
Heat exchanger (RCIC lube oil cooler) channel head	Pressure boundary	Copper alloy	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3-1, 022	D C
Heat exchanger (RCIC lube oil cooler) shell	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C

Table 3.2.2-5: Reactor Core Isolation Cooling 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 (RCIC lube oil cooler) shell	Pressure boundary	Copper alloy with greater than 15% Zn	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2-1, 050	C
Heat exchanger (RCIC lube oil cooler) tubes	Heat transfer	Copper alloy with greater than 15% Zn	Lubricating oil (external)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-78	3.2-1, 051	C
Heat exchanger (RCIC lube oil cooler) tubes	Heat transfer	Copper alloy with greater than 15% Zn	Treated water (internal)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-100	3.4-1, 018	B A
Heat exchanger (RCIC lube oil cooler) tubes	Pressure boundary	Copper alloy with greater than 15% Zn	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2-1, 050	C
Heat exchanger (RCIC lube oil cooler) tubes	Pressure boundary	Copper alloy with greater than 15% Zn	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3-1, 022	D C
Heat exchanger (RCIC lube oil cooler) tubesheet	Pressure boundary	Copper alloy	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2-1, 050	C
Heat exchanger (RCIC lube oil cooler) tubesheet	Pressure boundary	Copper alloy	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3-1, 022	D C

Table 3.2.2-5: Reactor Core Isolation Cooling 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**
Hose	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
Hose	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
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2-1, 004	A
Hose	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Hose	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Hose	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	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	Air – indoor uncontrolled (internal)	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 (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2-1, 004	A

Table 3.2.2-5: Reactor Core Isolation Cooling 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Orifice	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Orifice	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Orifice	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (internal)	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	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Orifice	Throttle	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A

Table 3.2.2-5: Reactor Core Isolation Cooling 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	Throttle	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Orifice	Throttle	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A

Table 3.2.2-5: Reactor Core Isolation Cooling 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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and 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 and 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.D2.E-29	3.2-1, 044	A
Piping and piping components	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-60	3.2-1, 016	E, 1
Piping and piping components	Pressure boundary	Carbon steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A

Table 3.2.2-5: Reactor Core Isolation Cooling 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 and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	V.D2.E-10	3.2-1, 001	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-60	3.2-1, 016	E, 1
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-09	3.2-1, 011	A
Piping and 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 and 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 and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Piping and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2-1, 004	A

Table 3.2.2-5: Reactor Core Isolation Cooling 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 and piping components	Pressure boundary	Stainless steel	Concrete (external)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	V.E.E-420	3.2-1, 078	B
Piping and piping components	Pressure boundary	Stainless steel	Concrete (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	V.E.EP-72	3.2-1, 053	B
Piping and piping components	Pressure boundary	Stainless steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A
Piping elements	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (external)	None	None	V.F.EP-15	3.2-1, 060	A

Table 3.2.2-5: Reactor Core Isolation Cooling 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 elements	Leakage boundary (spatial)	Glass	Treated water (internal)	None	None	V.F.EP-29	3.2-1, 060	A
Pump casing (RCIC barometric condenser condensate)	Leakage boundary (spatial)	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 condensate)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Pump casing (RCIC barometric condenser vacuum)	Leakage boundary (spatial)	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)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Pump casing (RCIC)	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)	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Rupture disk	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 3.2.2-5: Reactor Core Isolation Cooling 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**
Rupture disk	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
Rupture disk	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Rupture disk	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2-1, 004	A
Rupture disk	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Rupture disk	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Rupture disk	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A
Steam trap	Leakage boundary (spatial)	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
Steam trap	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Steam trap	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A

Table 3.2.2-5: Reactor Core Isolation Cooling 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
Steam trap	Leakage boundary (spatial)	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
Steam trap	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Steam trap	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Steam trap	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Steam trap	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
Steam trap	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.D2.E-29	3.2-1, 044	A
Steam trap	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A

Table 3.2.2-5: Reactor Core Isolation Cooling 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**
Steam trap	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
Steam trap	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
Steam trap	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Steam trap	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2-1, 004	A
Steam trap	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Steam trap	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Strainer (element)	Filter	Stainless steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1
Strainer (element)	Filter	Stainless steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Strainer (element)	Filter	Stainless steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 1

Table 3.2.2-5: Reactor Core Isolation Cooling 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Strainer (element)	Filter	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Strainer (element)	Filter	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Tank (RCIC barometric condenser)	Leakage boundary (spatial)	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
Tank (RCIC barometric condenser)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Tank (RCIC vacuum)	Leakage boundary (spatial)	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
Tank (RCIC vacuum)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A

Table 3.2.2-5: Reactor Core Isolation Cooling 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
Thermowell	Leakage boundary (spatial)	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
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Thermowell	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Thermowell	Leakage boundary (spatial)	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
Thermowell	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Thermowell	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
Thermowell	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Thermowell	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 3.2.2-5: Reactor Core Isolation Cooling 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**
Thermowell	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
Thermowell	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Turbine casing (RCIC)	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 casing (RCIC)	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Air – outdoor (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 (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A

Table 3.2.2-5: Reactor Core Isolation Cooling 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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Leakage boundary (spatial)	Cast austenitic 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 (spatial)	Cast austenitic 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 (spatial)	Cast austenitic stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A

Table 3.2.2-5: Reactor Core Isolation Cooling 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 (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B 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.D2.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Carbon steel	Air – outdoor (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	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) 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)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Pressure boundary	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A
Valve body	Pressure boundary	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-09	3.2-1, 011	A

Table 3.2.2-5: Reactor Core Isolation Cooling 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	Cast austenitic 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	Cast austenitic 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	Cast austenitic stainless steel	Air – outdoor (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	Air – outdoor (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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B 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	Air – indoor uncontrolled (internal)	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 (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2-1, 004	A

Table 3.2.2-5: Reactor Core Isolation Cooling 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2-1, 114	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2-1, 065	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 Torus Submerged Components Inspection (B.2.4.2) AMP provides supplemental sample-based inspections to manage loss of material of components submerged in the torus.

Table 3.2.2-6: Residual Heat Removal 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 steel	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 steel	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)	V.E.E-421	3.2-1, 079	A
Bolting (Closure)	Mechanical closure	Stainless steel	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	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	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	Treated water (external)	Loss of preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2-1, 015	A
Heat exchanger (RHR pump seal cooler) channel head	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) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-90	3.2-1, 023	A
Heat exchanger (RHR pump seal cooler) channel head	Pressure boundary	Carbon steel	Raw 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) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-90	3.2-1, 023	A

Table 3.2.2-6: Residual Heat Removal 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 (RHR pump seal cooler) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Heat exchanger (RHR pump seal cooler) shell	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	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Heat exchanger (RHR pump seal cooler) tubes	Heat transfer	Stainless steel	Raw water (internal)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.E-21	3.2-1, 027	A
Heat exchanger (RHR pump seal cooler) tubes	Heat transfer	Stainless steel	Treated water (external)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-74	3.2-1, 019	B A
Heat exchanger (RHR pump seal cooler) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Heat exchanger (RHR pump seal 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	3.2-1, 025	A
Heat exchanger (RHR pump seal cooler) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Heat exchanger (RHR) channel head with internal coating	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 3.2.2-6: Residual Heat Removal 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 (RHR) channel head with internal coating	Pressure boundary	Carbon steel	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-90	3.2-1, 023	A
Heat exchanger (RHR) channel head with internal coating	Pressure boundary	Carbon steel	Raw 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) channel head with internal coating	Pressure boundary	Carbon steel	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)	V.B.E-401	3.2-1, 072	A
Heat exchanger (RHR) channel head with internal coating	Pressure boundary	Carbon steel	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-90	3.2-1, 023	A
Heat exchanger (RHR) channel head with internal coating	Pressure boundary	Carbon steel	Raw water (internal)	Loss of material	RHR Heat Exchanger Augmented Inspection (B.2.4.1)	V.D2.EP-90	3.2-1, 023	E, 1
Heat exchanger (RHR) channel head with internal coating	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Heat exchanger (RHR) shell	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 3.2.2-6: Residual Heat Removal 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 (RHR) shell	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Heat exchanger (RHR) shell	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	RHR Heat Exchanger Augmented Inspection (B.2.4.1)	V.D2.EP-60	3.2-1, 016	E, 1
Heat exchanger (RHR) tubes	Heat transfer	Stainless steel	Raw water (internal)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.E-21	3.2-1, 027	A
Heat exchanger (RHR) tubes	Heat transfer	Stainless steel	Raw water (internal)	Reduction of heat transfer	RHR Heat Exchanger Augmented Inspection (B.2.4.1)	V.D2.E-21	3.2-1, 027	E, 1
Heat exchanger (RHR) tubes	Heat transfer	Stainless steel	Treated water (external)	Reduction of heat transfer	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-74	3.2-1, 019	B A
Heat exchanger (RHR) tubes	Heat transfer	Stainless steel	Treated water (external)	Reduction of heat transfer	RHR Heat Exchanger Augmented Inspection (B.2.4.1)	V.D2.EP-74	3.2-1, 019	E, 1
Heat exchanger (RHR) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Heat exchanger (RHR) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Heat exchanger (RHR) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2

Table 3.2.2-6: Residual Heat Removal 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 (RHR) tubes	Pressure boundary	Stainless steel	Treated water (external)	Loss of material	RHR Heat Exchanger Augmented Inspection (B.2.4.1)	V.D2.EP-73	3.2-1, 022	E, 1
Heat exchanger (RHR) tubesheet with internal coating	Pressure boundary	Carbon steel with stainless steel cladding	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Heat exchanger (RHR) tubesheet with internal coating	Pressure boundary	Carbon steel with stainless steel cladding	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)	V.B.E-401	3.2-1, 072	A
Heat exchanger (RHR) tubesheet with internal coating	Pressure boundary	Carbon steel with stainless steel cladding	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Heat exchanger (RHR) tubesheet with internal coating	Pressure boundary	Carbon steel with stainless steel cladding	Raw water (internal)	Loss of material	RHR Heat Exchanger Augmented Inspection (B.2.4.1)	V.D2.EP-91	3.2-1, 025	E, 1
Heat exchanger (RHR) tubesheet with internal coating	Pressure boundary	Carbon steel with stainless steel cladding	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Heat exchanger (RHR) tubesheet with internal coating	Pressure boundary	Carbon steel with stainless steel cladding	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A

Table 3.2.2-6: Residual Heat Removal 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 (RHR) tubesheet with internal coating	Pressure boundary	Carbon steel with stainless steel cladding	Treated water (external)	Loss of material	RHR Heat Exchanger Augmented Inspection (B.2.4.1)	V.D2.EP-73	3.2-1, 022	E, 1
Hose	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Hose	Leakage boundary (spatial)	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
Hose	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Motor casing (RHRSW 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
Motor casing (RHRSW pump)	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2-1, 049	A
Motor oil cooler (RHRSW pump) coils	Heat transfer	Stainless steel	Lubricating oil (external)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	V.D2.EP-79	3.2-1, 051	A
Motor oil cooler (RHRSW pump) coils	Heat transfer	Stainless steel	Raw water (internal)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.E-21	3.2-1, 027	A

Table 3.2.2-6: Residual Heat Removal 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
Motor oil cooler (RHRSW pump) coils	Pressure boundary	Stainless steel	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.C1.AP-138	3.3-1, 100	A
Motor oil cooler (RHRSW pump) coils	Pressure boundary	Stainless steel	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Motor oil cooler (RHRSW pump) coils	Pressure boundary	Stainless steel	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Motor oil cooler (RHRSW pump) coils	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Motor oil cooler (RHRSW pump) manifold	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
Motor oil cooler (RHRSW pump) manifold	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
Motor oil cooler (RHRSW pump) manifold	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
Motor oil cooler (RHRSW pump) manifold	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Nozzle	Spray	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (internal)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.EP-113b	3.2-1, 006	A

Table 3.2.2-6: Residual Heat Removal 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**
Nozzle	Spray	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.EP-113b	3.2-1, 006	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	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	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Orifice	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B 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
Orifice	Throttle	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2

Table 3.2.2-6: Residual Heat Removal 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	Throttle	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-440	3.2-1, 096	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Long-term loss of material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2-1, 090	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-400	3.2-1, 066	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-440	3.2-1, 096	A

Table 3.2.2-6: Residual Heat Removal 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 and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 4
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-440	3.2-1, 096	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-440	3.2-1, 096	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 4

Table 3.2.2-6: Residual Heat Removal 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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping and 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 and 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 and piping components	Pressure boundary	Carbon steel	Raw water (internal)	Long-term loss of material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2-1, 090	A
Piping and 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 and 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 and piping components	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Piping and 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	B
Piping and 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	B
Piping and piping components	Pressure boundary	Carbon steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-60	3.2-1, 016	E, 3

Table 3.2.2-6: Residual Heat Removal 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 and piping components	Pressure boundary	Carbon steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-60	3.2-1, 016	E, 3
Piping and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-406	3.2-1, 071	C
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3-1, 160	A
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	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 and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2

Table 3.2.2-6: Residual Heat Removal 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 and piping components	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
Piping and piping components	Pressure boundary	Nickel alloy	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.E-428	3.2-1, 022	B A
Piping and 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 and 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 and 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 and piping components	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Piping and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Piping elements	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (external)	None	None	V.F.EP-15	3.2-1, 060	A
Piping elements	Leakage boundary (spatial)	Glass	Treated water (internal)	None	None	V.F.EP-29	3.2-1, 060	A
Pump casing (RHR)	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 3.2.2-6: Residual Heat Removal 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 (RHR)	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Pump casing (RHRSW)	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 (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 (RHRSW)	Pressure boundary	Carbon steel	Raw 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 (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
Pump casing (RHRSW)	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Pump casings – Bowl assembly (RHRSW)	Pressure boundary	Cast austenitic 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
Pump casings – Bowl assembly (RHRSW)	Pressure boundary	Cast austenitic stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Strainer (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

Table 3.2.2-6: Residual Heat Removal 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 (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
Strainer (body)	Pressure boundary	Carbon steel	Raw water (internal)	Long-term loss of material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2-1, 090	A
Strainer (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
Strainer (body)	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Strainer (element)	Filter	Stainless steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Strainer (element)	Filter	Stainless steel	Treated water (external)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 3
Strainer (element)	Filter	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A
Strainer (element)	Filter	Stainless steel	Treated water (internal)	Loss of material	Torus Submerged Components Inspection (B.2.4.2)	V.D2.EP-73	3.2-1, 022	E, 3
Thermowell	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 3.2.2-6: Residual Heat Removal 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**
Thermowell	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Raw water (internal)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-440	3.2-1, 096	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw 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 (spatial)	Carbon steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-400	3.2-1, 066	A
Valve body	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-440	3.2-1, 096	A

Table 3.2.2-6: Residual Heat Removal 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 (spatial)	Carbon steel	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 4
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Raw water (internal)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-440	3.2-1, 096	A
Valve body	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-440	3.2-1, 096	A
Valve body	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 4

Table 3.2.2-6: Residual Heat Removal 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 (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B 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	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)	V.D2.E-434	3.2-1, 090	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
Valve body	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Valve body	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2-1, 016	B 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	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3-1, 040	A

Table 3.2.2-6: Residual Heat Removal 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	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 2
Valve body	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2-1, 022	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 RHR Heat Exchanger Augmented Inspection (B.2.4.1) AMP is used to manage loss of material of both the shell and tube sides of the Unit 1 and Unit 2 RHR heat exchangers.
2. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage wall thinning due to erosion of components exposed to raw water within the scope of the GL 89-13 program.
3. The Torus Submerged Components Inspection (B.2.4.2) AMP provides supplemental sample-based inspections to manage loss of material of components submerged in the torus.
4. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage wall thinning due to erosion of components exposed to raw water not within the scope of the GL 89-13 program.

Table 3.2.2-7: Standby Gas Treatment 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 steel	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 steel	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2-1, 015	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (external)	None	None	VII.J.AP-13	3.3-1, 116	A
Fan housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-13	3.3-1, 116	A
Filter housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (external)	None	None	VII.J.AP-13	3.3-1, 116	A
Filter housing	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-13	3.3-1, 116	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3-1, 091	A
Piping and 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

Table 3.2.2-7: Standby Gas Treatment 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 and 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.A.E-29	3.2-1, 044	A
Piping and 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	B
Piping and 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	B
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.B.EP-103b	3.2-1, 007	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.B.EP-103b	3.2-1, 007	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Rupture disk	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.B.EP-103b	3.2-1, 007	A
Rupture disk	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	A
Rupture disk	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	V.B.EP-103b	3.2-1, 007	A

Table 3.2.2-7: Standby Gas Treatment 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
Rupture disk	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	V.B.EP-107a	3.2-1, 004	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.A.E-29	3.2-1, 044	A
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	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% Zn	Air – indoor uncontrolled (internal)	None	None	V.F.EP-10	3.2-1, 057	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)	V.E.E-44	3.2-1, 040	A
Valve body	Pressure boundary	Gray cast iron	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

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 3.2.2-8: Standby Liquid Control 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**
Accumulator (SBLC pump) with internal coating	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
Accumulator (SBLC pump) with internal coating	Pressure boundary	Carbon steel	Sodium pentaborate solution (internal)	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	V.A.E-401	3.2-1, 072	A
Accumulator (SBLC pump) with internal coating	Pressure boundary	Carbon steel	Sodium pentaborate solution (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3-1, 203	B A
Bolting (Closure)	Mechanical closure	Carbon steel	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 steel	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)	V.E.E-421	3.2-1, 079	A
Bolting (Closure)	Mechanical closure	Stainless steel	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2-1, 015	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A

Table 3.2.2-8: Standby Liquid Control 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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Piping and 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 and 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 and piping components	Pressure boundary	Stainless steel	Sodium pentaborate solution (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3-1, 203	B A
Piping elements	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (external)	None	None	V.F.EP-15	3.2-1, 060	A
Piping elements	Leakage boundary (spatial)	Glass	Treated water (internal)	None	None	V.F.EP-29	3.2-1, 060	A
Pump casing (Injection)	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 (Injection)	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
Pump casing (Injection)	Pressure boundary	Stainless steel	Sodium pentaborate solution (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3-1, 203	B A

Table 3.2.2-8: Standby Liquid Control 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
Tank (Storage tank)	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
Tank (Storage tank)	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
Tank (Storage tank)	Pressure boundary	Stainless steel	Sodium pentaborate solution (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3-1, 203	B A
Tank (Test tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2-1, 007	A
Tank (Test tank)	Leakage boundary (spatial)	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
Tank (Test tank)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Thermowell	Pressure boundary	Stainless steel	Sodium pentaborate solution (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3-1, 203	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 3.2.2-8: Standby Liquid Control 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 (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B 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	Sodium pentaborate solution (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3-1, 203	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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

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 2.3.1, *Auxiliary Systems* as being subject to AMR. The systems, or portions of the systems, which are addressed in this section are described in the indicated sections.

- Condensate Transfer and Storage System (Section 2.3.3.1)
- Control Rod Drive System (Section 2.3.3.2)
- Containment Atmosphere Cooling System (Section 2.3.3.3)
- Control Building HVAC System (Section 2.3.3.4)
- Demineralized Water Supply System (Section 2.3.3.5)
- Drywell Pneumatic System (Section 2.3.3.6)
- Emergency Diesel Generators System (Section 2.3.3.7)
- Fire Protection System (Section 2.3.3.8)
- Fuel Pool Cooling and Cleanup System (Section 2.3.3.9)
- Instrument Air System (Section 2.3.3.10)
- Non-Safety Affecting Safety Systems (Section 2.3.3.11)
- Primary Containment Chilled Water System (Unit 2 Only) (Section 2.3.3.12)
- Process Radiation Monitoring System (Section 2.3.3.13)
- Radwaste System (Section 2.3.3.14)
- Reactor Building Closed Cooling Water System (Section 2.3.3.15)
- Reactor Building HVAC System (Section 2.3.3.16)
- Reactor Water Cleanup System (Section 2.3.3.17)
- Sampling System (Section 2.3.3.18)
- Plant Service Water System (Section 2.3.3.19)
- Torus Water Cleanup System (Section 2.3.3.20)
- Outside Structures HVAC System (Section 2.3.3.21)

3.3.2 Results

Table 3.3.2-1, Condensate Transfer and Storage System – Summary of Aging Management Evaluation

Table 3.3.2-2, Control Rod Drive System – Summary of Aging Management Evaluation

Table 3.3.2-3, Containment Atmosphere Cooling System – Summary of Aging Management Evaluation

Table 3.3.2-4, Control Building HVAC System – Summary of Aging Management Evaluation

Table 3.3.2-5, Demineralized Water Supply System – Summary of Aging Management Evaluation

Table 3.3.2-6, Drywell Pneumatic System – Summary of Aging Management Evaluation

Table 3.3.2-7, Emergency Diesel Generators System – Summary of Aging Management Evaluation

Table 3.3.2-8, Fire Protection System – Summary of Aging Management Evaluation

Table 3.3.2-9, Fuel Pool Cooling and Cleanup System – Summary of Aging Management Evaluation

Table 3.3.2-10, Instrument Air System – Summary of Aging Management Evaluation

Table 3.3.2-11, Non-Safety Affecting Safety Systems – Summary of Aging Management Evaluation

Table 3.3.2-12, Primary Containment Chilled Water System (Unit 2 Only) – Summary of Aging Management Evaluation

Table 3.3.2-13, Process Radiation Monitoring System – Summary of Aging Management Evaluation

Table 3.3.2-14, Radwaste System – Summary of Aging Management Evaluation

Table 3.3.2-15, Reactor Building Closed Cooling Water System – Summary of Aging Management Evaluation

Table 3.3.2-16, Reactor Building HVAC System – Summary of Aging Management Evaluation

Table 3.3.2-17, Reactor Water Cleanup System – Summary of Aging Management Evaluation

Table 3.3.2-18, Sampling System – Summary of Aging Management Evaluation

Table 3.3.2-19, Plant Service Water System – Summary of Aging Management Evaluation

Table 3.3.2-20, Torus Water Cleanup System – Summary of Aging Management Evaluation

Table 3.3.2-21, Outside Structures HVAC System – Summary of Aging Management Evaluation

3.3.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.3.2.1.1 Condensate Transfer and Storage System

Materials

The materials of construction for the condensate transfer and storage system components are:

- Aluminum
- Carbon steel
- Cast austenitic stainless steel
- Galvanized steel
- Stainless steel

Environments

The condensate transfer and storage system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the condensate transfer and storage system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the condensate transfer and storage 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)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
- Water Chemistry (B.2.3.2)

3.3.2.1.2 Control Rod Drive System

Materials

The materials of construction for the CRD system components are:

- Carbon steel
- Copper alloy
- Stainless steel

Environments

The CRD system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- 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

Aging Management Programs

The following AMPs manage the aging effects for the CRD components:

- Bolting Integrity (B.2.3.10)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.3 Containment Atmosphere Cooling System

Materials

The material of construction for the CAC system components is:

- Copper alloy

Environments

The CAC system components are exposed to the following environments:

- Air – indoor uncontrolled
- Raw water

Aging Effects Requiring Management

The following aging effects associated with the CAC system require management:

- Flow blockage
- Loss of material
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the CAC system components:

- Open-Cycle Cooling Water System (B.2.3.11)

3.3.2.1.4 Control Building HVAC System

Materials

The materials of construction for the control building HVAC system components are:

- Carbon steel
- Copper alloy
- Elastomer
- Galvanized steel

- Gray cast iron
- Stainless steel

Environments

The control building HVAC system components are exposed to the following environments:

- Air – dry
- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Closed-cycle cooling water
- Gas
- Raw water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the control building HVAC 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 - erosion

Aging Management Programs

The following AMPs manage the aging effects for the control building HVAC 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)
- Open-Cycle Cooling Water System (B.2.3.11)
- Selective Leaching (B.2.3.21)

3.3.2.1.5 Demineralized Water Supply System

Materials

The materials of construction for the demineralized water supply system components are:

- Carbon steel
- Stainless steel

Environments

The demineralized water supply system components are exposed to the following environments:

- Treated water
- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects associated with the demineralized water supply system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Demineralized Water Supply 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)

3.3.2.1.6 Drywell Pneumatic System

Materials

The materials of construction for the drywell pneumatic system components are:

- Carbon steel
- Copper alloy
- Stainless steel

Environments

The drywell pneumatic system components are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled

- Gas
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the drywell pneumatic 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 drywell pneumatic 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)

3.3.2.1.7 Emergency Diesel Generators System

Materials

The materials of construction for the emergency diesel generator (EDG) system components are:

- Carbon steel
- Copper alloy
- Copper alloy with greater than 15% Zn
- Galvanized steel
- Glass
- Gray cast iron
- Stainless steel

Environments

The EDG system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Closed-cycle cooling water
- Closed-cycle cooling water >140°F
- Diesel exhaust
- Fuel oil
- Lubricating oil
- Raw water

- Soil
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the EDG 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 - erosion

Aging Management Programs

The following AMPs manage the aging effects for the EDG 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)
- Water Chemistry (B.2.3.2)

3.3.2.1.8 Fire Protection System

Materials

The materials of construction for the FP system components are:

- Aluminum
- Carbon steel
- Copper alloy
- Copper alloy with greater than 15% Zn
- Ductile iron
- Ductile iron (with internal cement lining)
- Elastomer
- Galvanized steel
- Gray cast iron

- Gray cast iron (with internal cement lining)
- Malleable iron
- Stainless steel

Environments

The FP system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Fuel oil
- Gas
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the FP 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 - erosion

Aging Management Programs

The following AMPs manage the aging effects for the FP 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)
- Fuel Oil Chemistry (B.2.3.18)
- 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)

3.3.2.1.9 Fuel Pool Cooling and Cleanup System

Materials

The material of construction for the FPCC system components are:

- Carbon steel
- Ductile iron

- Stainless steel

Environments

The FPCC 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 FPCC system require management:

- Cracking
- Loss of coating or integrity lining
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the FPCC 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)

3.3.2.1.10 Instrument Air System

Materials

The materials of construction for the instrument air system components are:

- Carbon steel
- Stainless steel
- Copper alloy
- Copper alloy with greater than 15% Zn

Environments

The instrument air system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – dry
- Gas

Aging Effects Requiring Management

The following aging effects associated with the instrument air system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the instrument 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)

3.3.2.1.11 Non-Safety Affecting Safety Systems

Materials

The materials of construction for the non-safety affecting safety systems components are:

- Carbon steel
- Copper alloy
- Glass
- Stainless steel

Environments

The non-safety affecting safety systems components are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Lubricating oil
- Lubricating oil (waste oil)
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the non-safety affecting safety systems 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 non-safety affecting safety systems 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)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.12 Primary Containment Chilled Water System (Unit 2 Only)

Materials

The materials of construction for the PCCW system components are:

- Carbon steel
- Copper alloy
- Copper alloy with greater than 15% Zn
- Glass
- Gray cast iron
- Stainless steel

Environments

The PCCW system components are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Raw water

Aging Effects Requiring Management

The following aging effects associated with the PCCW system require management:

- Cracking
- Loss of material
- Loss of preload
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the PCCW system (Unit 2 only) 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)
- Selective Leaching (B.2.3.21)

3.3.2.1.13 Process Radiation Monitoring System

Materials

The materials of construction for the PRM system components are:

- Carbon steel
- Stainless steel

Environments

The PRM system components are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects associated with the PRM system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the PRM system components:

- Bolting Integrity (B.2.3.10)
- One-Time Inspection (B.2.3.20)

3.3.2.1.14 Radwaste System

Materials

The materials of construction for the radwaste system components are:

- Carbon steel
- Stainless steel

Environments

The radwaste system components are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the radwaste 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 radwaste 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)

3.3.2.1.15 Reactor Building Closed Cooling Water System

Materials

The materials of construction for the RBCCW system components are:

- Carbon steel
- Copper alloy with greater than 15% Zn
- Gray cast iron
- Low alloy steel
- Stainless steel

Environments

The RBCCW 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 RBCCW system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the RBCCW 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)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.16 Reactor Building HVAC System

Materials

The materials of construction for the reactor building HVAC system components are:

- Aluminum
- Carbon steel
- Copper alloy
- Copper alloy with greater than 15% Zn
- Elastomer
- Galvanized steel
- Stainless steel

Environments

The reactor building HVAC system components are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Raw water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the reactor building HVAC system require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the reactor building HVAC 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)
- Water Chemistry (B.2.3.2)

3.3.2.1.17 Reactor Water Cleanup System

Materials

The materials of construction for the RWCU system components are:

- Carbon steel
- Ductile iron
- Stainless steel

Environments

The RWCU system components are exposed to the following environments:

- Air – indoor uncontrolled
- Closed cycle cooling water
- Treated water
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the RWCU system require management:

- Cracking
- Cumulative fatigue damage
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning - erosion
- Wall thinning - FAC

Aging Management Programs

The following AMPs manage the aging effects for the RWCU 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)
- 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)

3.3.2.1.18 Sampling System

Materials

The materials of construction for the sampling system are:

- Aluminum
- Carbon steel
- Stainless steel

Environments

The sampling system components are exposed to the following environments:

- Air – indoor uncontrolled
- Closed cycle cooling water
- Gas
- Treated water >140°F

Aging Effects Requiring Management

The following aging effects associated with the sampling system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the sampling 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)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.19 Plant Service Water System

Materials

The materials of construction for the PSW system components are:

- Carbon steel
- Copper alloy with greater than 15% Zn

- Galvanized steel
- Glass
- Gray cast iron
- Low alloy steel
- Stainless steel

Environments

The PSW system components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Lubricating oil
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the PSW system require management:

- Cracking
- Flow blockage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning - erosion

Aging Management Programs

The following AMPs manage the aging effects for the PSW 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)
- 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)

3.3.2.1.20 Torus Water Cleanup System

Materials

The materials of construction for the TWC system components are:

- Carbon steel
- Stainless steel

Environments

The TWC system components are exposed to the following environments:

- Air – indoor uncontrolled
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the TWC system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the TWC 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)

3.3.2.1.21 Outside Structures HVAC System

Materials

The materials of construction for the outside structures HVAC system components are:

- Carbon steel
- Stainless steel

Environments

The outside structures HVAC system components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following aging effects associated with the outside structures HVAC system require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the outside structures HVAC system components:

- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)

3.3.2.2 Further Evaluation of Aging Management as Recommended by GALL-SLR

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.

3.3.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be TLAAs, as defined in 10 CFR 54.3 (TN4878). The 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 plants-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 Fatigue of Cranes (Crane Cycle Limits) as discussed in Section 4.7.1.

3.3.2.2.2 Cracking due to Stress Corrosion Cracking and Cyclic Loading

Cracking due to SCC and cyclic loading could occur in SS PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60°C (140°F) in the chemical and volume control system. The existing AMP for monitoring and control of primary water chemistry in PWRs (GALL-SLR Report AMP XI.M2, "Water Chemistry") manages the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading. Therefore, the effectiveness of the water chemistry control program should be verified to ensure that cracking is not occurring. If a search of plant-specific OE does not reveal that cracking has occurred in nonregenerative heat exchanger tubing, this aging effect can be considered to be adequately managed by GALL-SLR Report AMP XI.M2. However, if cracking has occurred in nonregenerative heat exchanger tubing, the GALL-SLR Report recommends that AMP XI.M21A, "Closed Treated Water Systems," be evaluated for inclusion of augmented requirements to conduct temperature and radioactivity monitoring of the shell-side water, and where component configuration permits, periodic eddy current testing of tubes.

Not applicable. This further evaluation item is applicable to PWRs only.

3.3.2.2.3 Cracking due to Stress Corrosion Cracking

Cracking due to SCC could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (i) uninsulated, (ii) insulated, (iii) in the vicinity of insulated components, or (iv) in the vicinity of potentially transportable halogens.

Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect which requires management if: (i) plant-specific OE does not reveal a history of SCC and (ii) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the LRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage cracking due to SCC: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surface of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "Detection of Aging Effects" program element in GALL-SLR Report AMP XI.M32.

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Ambient air at HNP is not subject to a marine atmosphere. The closest highway is US Highway 1 and the use of salt/ash to de-ice roadways is a rare occurrence in the south Georgia environments. A review of the over 30,000 CRs created during the last 10 years of operation 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 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 HNP for insulated stainless steel components for this environment. This indicates 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 10 CFR Part 50, Appendix B 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: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components; or (iv) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel-alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other parts below the component. For outdoor insulated SS and nickel-alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel-alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect which requires management for SS and *nickel-alloy components if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (ii) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur in the presence of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel-alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of 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 mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. 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.

Ambient air at HNP is not subject to a marine atmosphere. The closest highway is US Highway 1 and the use of salt/ash to de-ice roadways is a rare occurrence in the south Georgia environments. A review of the over 30,000 CRs created during the last 10 years of operation 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 and nickel alloy 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 stress corrosion cracking. Loss of material has not been identified as an aging effect at HNP for insulated stainless steel or nickel alloy components for this environment. This indicates 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 and nickel alloy components exposed to air indoor uncontrolled, air outdoor, and condensation, and, insulated stainless steel and nickel alloy components exposed to condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B 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 BTP IQMB-1 (Appendix A.2 of this SRP-SLR.)

Quality Assurance 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 Operating Experience 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: (i) a 10 year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (ii) a five year search of plant-specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant-specific acceptance criteria or experiencing a reduction in wall thickness greater than 50% (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M20, "Open Cycle Cooling Water System," GALL-SLR Report AMP XI.M27, "Fire Water

System," or GALL-SLR Report Section AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increases inspections would be implemented.

The applicant states: (i) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (ii) the basis for the adequacy of augmented or lack of augmented inspections, (iii) the trend of which parameters will be followed as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (iv) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (v) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant-specific OE, two instances of 360 º 30% wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the CLB intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in environments other than raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Based on plant specific OE, recurring internal corrosion is an applicable aging effect for steel components in raw water systems that use water from the Altamaha 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 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 are provided for demonstrating *that the specific material is not susceptible to SCC the ambient environment is not aggressive in nature. Cracking due to SCC is an aging effect that requires management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.*

<u>Susceptible Material</u>: If the material is not susceptible to SCC then cracking is not an aging effect which requires management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, that determines whether the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper type, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper;*
- *5xxx series alloys with a magnesium content of 3.5 wt% or greater;*
- *6xxx series alloys in the F temper;*
- *7xxx series alloys in the F, T5x, or T6x temper;*
- *2xx.x and 7xx.x series alloys;*
- *3xx.x series alloys that contain copper; and*
- *5xx.x series alloys with a magnesium content of greater than 8 wt%.*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, 6063-T6, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, and product form. For tempers not addressed above, the basis used to determine that the alloy is not susceptible and technical information substantiating the basis is added to the SLRA.

<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 that requires management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys include the presence of aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation layer or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, halide concentrations sufficient to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. The GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings for internal or external coatings.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that cracking is not occurring in aluminum alloy components. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B CAP. The One-Time Inspection AMP is described in Section B.2.3.20. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage cracking for the HNP Unit 1 condensate storage tank.

3.3.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a highly alkaline environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the highly alkaline environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrate the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (i) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (ii) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (iii) the piping is not potentially exposed to groundwater. For SS components, loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

The Unit 2 condensate storage tank is the only stainless steel component exposed to concrete that is susceptible to cracking, and the fire water storage tank is the only steel component exposed to concrete that is susceptible to loss of material. Other steel or stainless steel components exposed to concrete are not subject to wetting so loss of material and cracking are not applicable aging effects. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material to due to crevice or pitting corrosion and cracking due to stress corrosion cracking for the HNP Unit 2 condensate storage tank. The Fire Water System (B.2.3.16) AMP is used to manage loss of material due to crevice or pitting corrosion for the fire water storage tank.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture.

The moisture level and halide concentration in atmospheric and uncontrolled air greatly depends on the geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect which requires management for aluminum alloys if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (ii) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. Alternatively, loss of material due to pitting and crevice corrosion need not be managed if the type of aluminum is not susceptible to cracking and plant-specific operating experience does not reveal any issues related to loss of material due to pitting or crevice corrosion. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur in the presence of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of 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.*

The applicant may mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL- SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

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 alloy components. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material to due to crevice or pitting corrosion for the HNP Unit 1 condensate storage tank.

3.3.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Auxiliary System components:

- Section 4.3, *Metal Fatigue*
- Section 4.7.1, *Fatigue of Cranes (Crane Cycle Limits)*

3.3.3 Conclusion

The Auxiliary 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 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 the 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 Fatigue of Cranes (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. 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 piping and piping components exposed to a treated water environment. Further evaluation is documented in Section 3.3.2.2.1.
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.				

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, 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 indoor controlled, and air outdoor. Further evaluation is documented in Section 3.3.2.2.3.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP) / TLAA**	**Further Evaluation Recommended**	**Discussion**
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. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of stainless steel piping and piping components exposed to air indoor uncontrolled, air indoor controlled, and air outdoor. 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.				
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.

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, 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, and soil.
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 reactor water cleanup 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	Not applicable. There are no stainless steel or steel with stainless steel cladding heat exchanger components exposed to treated borated water >60°C (>140°F) or treated water >60°C (>140°F).
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. 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.

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, 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. 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. This line item is also applied to components in the ESF Systems.
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 spent fuel pool seismic restraints 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, 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.

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, 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.
3.3-1, 034	Nickel alloy, copper alloy piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage of copper alloy piping and piping component exposed to raw water. This line item is also applied to components in the ESF Systems.
3.3-1, 037	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage of steel piping and piping components exposed to raw water. This line item is also applied to components in the 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, 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.
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. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage in stainless steel piping and piping components exposed to raw water. This line item is also applied to components in the ESF Systems.
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 AMP (B.2.3.11) is used to manage reduction of heat transfer for copper alloy heat exchanger tubes 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, 043	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage cracking of stainless steel piping and 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	Not applicable. There are no stainless steel or steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F) in the Auxiliary Systems.
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 is also 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.

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, 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 primary containment chilled water system evaporator (heat exchanger) shell.
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.
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.

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, 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 copper alloy heat exchanger tubes exposed to closed-cycle cooling water.
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.

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, 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 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	Not applicable. There are no steel piping, piping components, or tanks exposed to condensation in the Auxiliary Systems. The air indoor uncontrolled environment is used in lieu of the condensation environment.

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 with exception. The Fire Protection (B.2.3.15) AMP is used to manage hardening, loss of strength, and shrinkage of elastomer fire barrier penetration seals exposed to air indoor uncontrolled. This line item is used to evaluate fire barrier penetration seals 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 with exception. The Fire Protection (B.2.3.15) AMP is used to manage loss of material of steel carbon dioxide fire suppression system piping and piping 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, 059	Steel fire rated doors exposed to air	Loss of material due to wear	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191 with exception. This line is also applied to cable tray fire barriers and hold-down straps and fasteners. The Fire Protection (B.2.3.15) AMP is used to manage loss of material of steel fire rated doors, cable tray fire barriers, and hold-down straps and fasteners exposed to air. This line item is used to evaluate fire rated doors for various structures and commodity groups in the Plant Structures in Section 3.5.
3.3-1, 060	Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M26, "Fire Protection," and AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception for the Fire Protection (B.2.3.15) AMP. 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.

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, 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.
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. 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 and piping components exposed to raw water.
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	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 aluminum 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, 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. 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. 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.
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. 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.

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, 072	Gray cast iron, ductile iron, malleable 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, malleable iron, and copper alloy >15% Zn piping, piping components, and heat exchanger components exposed to raw water, treated water, closed-cycle cooling water, and soil. This line item is also applied to components in the ESF Systems.
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 ducting components exposed to air indoor uncontrolled, air indoor controlled, and air outdoor.
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 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.

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, 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, air indoor controlled, and air outdoor.
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.

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, 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 hardening or loss of strength for elastomer piping, piping components, ducting and ducting components exposed to air indoor uncontrolled, air indoor controlled, or air outdoor. The Fire Water System (B.2.3.16) AMP is used to manage flow blockage and hardening or loss of strength for expansion joints exposed to raw water in the Fire Protection System.
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.

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 air indoor uncontrolled, which is used in lieu of 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	Not applicable. There are no steel ducting and components exposed to condensation in the Auxiliary Systems. The air indoor uncontrolled environment is used in lieu of the condensation environment.
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, tanks, drip pans, and heat exchanger components exposed to waste water. This line item is also applied to components in the 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, 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	Not used. Loss of material of copper alloy piping and piping components exposed to raw water are addressed by line items 3.3-1, 034, 3.3-1, 064, and 3.3-1, 072.
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, ducting components, and drip pans 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. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of stainless steel ducting and ducting components exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.3.2.2.3.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP) / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 095	Copper alloy, stainless steel, nickel alloy piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of stainless steel and copper alloy piping, piping components, and tanks exposed to waste water.
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 ducting components exposed to air indoor uncontrolled, indoor controlled air, or air outdoor. The Fire Water System (B.2.3.16) AMP is used to manage loss of material of expansion joints exposed to raw water in the Fire Protection System.

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, 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 and stainless steel 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 used. The air indoor uncontrolled environment is used for the external surfaces of steel heat exchanger components and is addressed by line items 3.3-1, 078 and 3.3-1, 080.
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. 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 3.3-1: 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. 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.
3.3-1, 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. 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, piping components, and heat exchanger components exposed to lubricating oil. This line item is also applied to components in the 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	Not applicable. There are no aluminum heat exchanger components exposed to lubricating oil in the Auxiliary Systems.
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 Boral® plates 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.

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, 104	High-density polyethylene (HDPE), CFRP, fiberglass piping, piping components exposed to soil, concrete	Loss of material, cracking, and blistering due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture, general corrosion (steel only), erosion, chemical attack, or wear	AMP XI.M41, "Buried and Underground Piping and Tanks" or AMP XI.M43 “High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping”	No	Not applicable. There are no HDPE, CFRP, or fiberglass piping or piping components exposed to soil or concrete in the Auxiliary Systems.
3.3-1, 107	Stainless steel, nickel alloy piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191 with exception. 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.
3.3-1, 108	Titanium, super austenitic, copper alloy, stainless steel, nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC (super austenitic, copper alloy, stainless steel, nickel alloy; soil environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191 with exception. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage loss of material of stainless steel and copper alloy piping, piping components, and closure bolting 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, 109	Steel piping, piping components, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191 with exception. The 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.
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 item 3.3-1, 244.
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.

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, 112	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Not applicable. There are no steel piping and piping components exposed to concrete that are not subject to wetting in the Auxiliary Systems. 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. There are no aging effects that require management for copper piping, piping components, and heat exchanger components exposed to gas, air indoor uncontrolled, air indoor controlled, or air outdoor.
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.

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, 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. Loss of material for galvanized steel components within the fire protection system are addressed by lines 3.3-1, 078 and 3.3-1, 089.
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, raw water, treated water, closed-cycle cooling water, lubricating oil, or raw water.
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 glass piping components 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, 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, piping components, ducting, and ducting components exposed to gas or indoor controlled air.
3.3-1, 122	Titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	None	None	No	Not applicable. There are no titanium heat exchanger components or piping and piping components exposed to air indoor uncontrolled or are outdoors 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," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. Titanium heat exchanger components other than tubes exposed to raw water with cracking as the applicable aging effect are addressed by line 3.4-1, 130.

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	Not used. Cracking of stainless steel piping and piping components exposed to treated water >60°C (>140°F) are addressed by line 3.3-1, 244.
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, spent fuel pool gates, and structural bolting 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.2.3.17) 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. This line item is also applied to components in the ESF and Steam and Power Conversion 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, 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. The Open-Cycle Cooling Water System (B.2.3.11) 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 for steel piping, piping components, and heat exchanger components exposed to raw water. This line item is also applied to components in the ESF Systems. Further evaluation is documented in Section 3.3.2.2.7.
3.3-1, 128	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation, raw water	Loss of material due to general, pitting, crevice corrosion, MIC (soil, raw water only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no steel 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, 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 and air indoor uncontrolled.
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. The Fire Water System (B.2.3.16) AMP is used to manage flow blockage of aluminum and copper alloy nozzles 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, 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. This line is also applied to heat exchanger components. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of copper alloy (>15% Zn) heat exchanger components, piping, and piping components exposed to air indoor uncontrolled. This line item is also applied to components in the ESF Systems.
3.3-1, 133	HDPE, CFRP underground piping, piping components	Cracking, blistering, and loss of material due to exposure to temperature, moisture, general corrosion (steel only), erosion, chemical attack, or wear	AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M43 "High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping"	No	Not applicable. There are no HDPE or CFRP 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 and flow blockage of non GL 89-13 steel and stainless steel 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	Not used. Loss of material in steel and stainless steel pump casing exposed to waste water is addressed by lines 3.3-1, 091 and 3.3-1, 095.
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. The Fire Water System (B.2.3.16) AMP is used to manage loss of material of steel fire water storage tanks exposed to air outdoor, concrete, 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, 137	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water, raw water, waste water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material in steel, stainless steel, and aluminum tanks exposed to treated water 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 exposed to raw water, waste water, and 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, 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	Not used. Piping, piping components, heat exchangers, and tanks exposed to raw water, treated water, or waste water are addressed by line 3.3-1, 138.
3.3-1, 140	Gray cast iron, ductile iron, malleable iron piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not used. Gray cast iron, ductile iron, and malleable iron piping components with internal coatings/linings exposed to raw water are addressed by line 3.3-1, 138.
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 stainless steel closure bolting 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, 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 with exception. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage cracking of steel and stainless piping, piping components, and tanks exposed to soil. The only components exposed to concrete that are susceptible to cracking are the Unit 1 and Unit 2 condensate storage tanks, which are addressed by items 3.3-1, 186 and 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, air outdoor, and 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, 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.
3.3-1, 149	Fiberglass piping, piping components, ducting, ducting components exposed to air – outdoor	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no fiberglass piping, piping components, ducting, or ducting components exposed to air outdoor 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	Not applicable. There are no fiberglass piping, piping components, ducting, or ducting components exposed to 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, 151	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not used. Heat exchanger components internal to other components that are susceptible to reduction of heat transfer due to fouling exposed to air indoor uncontrolled are addressed by line 3.3-1, 096a.
3.3-1, 155	Stainless steel piping, piping components, and tanks exposed to waste water >60°C (>140°F)	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no stainless steel piping, piping components, or tanks exposed to waste water >60°C (>140°F) in the Auxiliary Systems.
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. 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, ducting components, fan housings, and access hole covers exposed to air outdoor.
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.

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, 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 in the Auxiliary Systems.
3.3-1, 160	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, raw water, waste water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.3.11) and Closed Treated Water Systems (B.2.3.12) AMPs are used to manage cracking in copper alloy >15% Zn components exposed to raw water and closed-cycle cooling water, respectively. This line item is also applied to components in the ESF 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 applicable. There are no copper alloy heat exchanger tubes exposed to condensation in the Auxiliary Systems. The air indoor uncontrolled environment is used in lieu of the condensation environment.
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.

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, 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.
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	Not applicable. There are no steel or copper alloy piping or piping components exposed to steam in the Auxiliary Systems.
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	Not applicable. There are no stainless steel piping or piping components exposed to steam in the Auxiliary Systems.
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 exposed to outdoor air in the Auxiliary Systems.
3.3-1, 175	Fiberglass piping, piping components, tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no fiberglass components exposed to raw water (potable), treated water, or 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, 176	Fiberglass piping, piping components, tanks exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no fiberglass piping, piping components, tanks not covered by NRC GL 89-13 exposed to raw water (potable), treated water, or waste water in the Auxiliary Systems.
3.3-1, 177	Fiberglass piping, piping components exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	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.

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, 181	Titanium piping, piping components exposed to condensation	None	None	No	Not applicable. There are no titanium piping or piping components exposed to condensation in the Auxiliary Systems.
3.3-1, 182	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage reduced thermal insulation resistance in non-metallic thermal insulation exposed to air outdoor and air indoor uncontrolled. This line item is used to evaluate structural items in Section 3.5.
3.3-1, 184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no PVC components exposed to concrete in the Auxiliary Systems.
3.3-1, 185	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no aluminum fire water storage tanks 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, 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)	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage cracking of aluminum tanks exposed to air outdoor and concrete. Further evaluation is documented in Section 3.3.2.2.8.
3.3-1, 189	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of aluminum piping and piping components exposed to air indoor uncontrolled. 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, 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 raw water and waste water.
3.3-1, 194	PVC, CFRP piping, piping components, and tanks exposed to soil	Loss of material, cracking, and blistering due to general corrosion (steel only) erosion, chemical attack, moisture, or wear	AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M43 “High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping”	No	Not applicable. There are no PVC or CFRP piping or piping components exposed to soil 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, 195	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping and piping components exposed to raw water, treated water, or raw water (potable) in the Auxiliary Systems.
3.3-1, 196	HDPE piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking, blistering; loss of material due to exposure to radiation, temperature, or moisture; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no HDPE piping 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, 197	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function exposed to any external environment except soil, concrete	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not used. Loss of material in metallic fire water system piping exposed to air indoor is addressed by lines 3.3-1, 006, 3.3-1, 058, 3.3-1, 078, 3.3-1, 089, and 3.3-1, 234.
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. Loss of material in metallic fire water system piping exposed to raw water is addressed by lines 3.3-1, 064, 3.3-1, 065, and 3.3-1, 130.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP) / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 associated with cranes exposed to air indoor uncontrolled. This line item is used to evaluate structural items 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 Unit 2 condensate storage tank, which is addressed by items 3.3-1, 229 and 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 and steel with internal coating piping, piping components, and heat exchanger components exposed to treated water or sodium pentaborate solution This line item is also applied to components in the ESF system and the Reactor Vessel, Internals, and Reactor Coolant 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, 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)	Not used. Although various systems contain insulated piping, cracking is addressed by line item 3.2-1, 007. 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, copper alloy, or titanium 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 or cracking.

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.M43 “High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping”	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	Consistent with NUREG-2191. The Selective Leaching (B.2.3.21) AMP is used to manage loss of material of copper alloy (>15% Zn) piping and piping components 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, 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.
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.

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, 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 components and tanks exposed to air indoor uncontrolled. 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	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material in aluminum tanks exposed to concrete.
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)	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material in aluminum tanks exposed to air outdoor. 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)	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material in stainless steel tanks exposed to air outdoor. 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, 229	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material in stainless steel tanks exposed to concrete.
3.3-1, 230	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage cracking in stainless steel tanks 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)	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage cracking in stainless steel tanks exposed to air outdoor. Further evaluation is documented in Section 3.3.2.2.3.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP) / TLAA**	**Further Evaluation Recommended**	**Discussion**
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)	Not used. Although various systems contain insulated piping, loss of material is addressed by line item 3.3-1, 006. Further evaluation is documented in Section 3.3.2.2.4.
3.3-1, 233	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no insulated aluminum piping, piping components, or tanks 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, 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 and piping components exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.3.2.2.10.
3.3-1, 235	Metallic piping, piping components exposed to air-dry (internal)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M24, "Compressed Air Monitoring"	No	Consistent with NUREG-2191. 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 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, 236	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with 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 titanium heat exchanger tubes and tubesheets exposed to treated water. This line item is used to evaluate components in the Steam and Power Conversion Systems.
3.3-1, 237	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping and piping components exposed to treated water 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 heat exchanger tubes 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, 239	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not applicable. There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping and piping components exposed to closed-cycle cooling water 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. 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, 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.

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, 242	Aluminum heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no aluminum heat exchanger components in the Auxiliary Systems. Further evaluation is documented in Section 3.3.2.2.10.
3.3-1, 244	Stainless steel, nickel alloy piping, piping components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	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 and piping 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, 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. Further evaluation is documented in Section 3.3.2.2.10.
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 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, 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 used. Aluminum piping or piping components exposed to raw water or waste water are addressed by line 3.3-1, 065. Further evaluation is documented in Section 3.3.2.2.10.
3.3-1, 248	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. 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	Not applicable. There are no steel heat exchanger tubes internal to components exposed to air outdoor, air indoor uncontrolled, or condensation 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, 250	Steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of steel reactor coolant pump oil collection system piping and piping components exposed to lubricating oil (waste oil).
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, CFRP piping, piping components exposed to raw water, raw water (potable), treated water, waste water	Cracking, blistering, loss of material due to wear, tearing, delamination, void, debonding, chemical attack and exposure to moisture; flow blockage due to fouling, delamination, debonding, or tearing	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" or AMP XI.M43 “High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping”	No	Not applicable. There are no PVC or CFRP piping or piping components exposed to raw water, raw water (potable), treated water, or 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, 254	Aluminum heat exchanger components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no aluminum heat exchanger components exposed to air or condensation in the Auxiliary Systems. Further evaluation is documented in Section 3.3.2.2.8.
3.3-1, 255	Metallic fire damper housings exposed to air	Loss of material due to general, pitting, crevice corrosion; cracking due to SCC	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191 with exception. The Fire Protection (B.2.3.15) AMP is used to manage loss of material of steel fire damper and vent housings exposed to air indoor uncontrolled. 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, 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 copper alloy heat exchanger tubes exposed to lubricating oil.
3.3-1, 258	Metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. Steel piping and piping components exposed to waste water are addressed by line 3.3-1, 091.
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 used. Aluminum piping and piping components exposed to raw water are addressed by line 3.3-1, 065.
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, cracking, and loss of preload of metallic HVAC closure bolting 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, 261	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water, raw water	Cracking due to SCC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium heat exchanger tubes susceptible to cracking or flow blockage in the Auxiliary Systems.
3.3-1, 262	Titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water or treated water 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	Not applicable. There are no polymeric piping, piping components, ducting, ducting components, or seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, or soil.

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, 264	Steel piping, piping components, and tanks exposed to treated water, sodium pentaborate solution	Long-term loss of material due to general corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no steel piping, piping components, or tanks exposed to treated water or sodium pentaborate solution that are susceptible to long-term loss of material.
3.3-1, 265	Steel heat exchanger tubes exposed to fuel oil	Reduction of heat transfer due to fouling	AMP XI.M30, “Fuel Oil Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Not applicable. There are no steel heat exchanger tubes exposed to fuel oil in the Auxiliary Systems.
3.3-1, 266	Steel heat exchanger tubes exposed to fuel oil	Reduction of heat transfer due to fouling	AMP XI.M30, “Fuel Oil Chemistry”	No	Not applicable. There are no steel heat exchanger tubes exposed to fuel oil in the Auxiliary Systems.
3.3-1, 267	Subliming compound fireproofing/fire barriers (Thermolag ®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air	Loss of material due to abrasion, flaking, vibration; cracking / delamination due to chemical reaction, settlement; change in material properties due to gamma irradiation exposure; separation	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191 with exception. The Fire Protection (B.2.3.15) AMP is used to manage loss of material, change in material properties, cracking, and delamination, for subliming compound fireproofing exposed to air indoor uncontrolled. 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, 268	Cementitious coating fireproofing/fire barriers (Pyrocrete, BIO™ K-10 Mortar, Cafecote, and other similar materials) exposed to air	Loss of material due to abrasion, exfoliation, elevated temperature, flaking, spalling; cracking / delamination due to chemical reaction, elevated temperature, settlement, vibration; change in material properties due to elevated temperature, gamma irradiation exposure; separation	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191 with exception. The Fire Protection (B.2.3.15) AMP is used to manage loss of material, change in material properties, cracking, and delamination, for cementitious coating fireproofing 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 due to abrasion, flaking, cracking / delamination due to settlement; change in material properties due to gamma irradiation exposure; separation	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191 with exception. The Fire Protection (B.2.3.15) AMP is used to manage loss of material, cracking, delamination, and change in material properties of silicate fireproofing and 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: Condensate Transfer and Storage 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 steel	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 steel	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 steel	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 steel	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	Stainless steel	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	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	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	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	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	Air – outdoor (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A

Table 3.3.2-1: Condensate Transfer and Storage 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 and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Piping and piping components	Pressure boundary	Galvanized 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, 1
Piping and piping components	Pressure boundary	Galvanized steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A , 1
Piping and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3-1, 006	A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time	VII.E4.AP-110	3.3-1, 203	B A

Table 3.3.2-1: Condensate Transfer and Storage 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**
					Inspection (B.2.3.20)			
Tank (Unit 1 condensate storage tank)	Pressure boundary	Aluminum	Air – outdoor (external)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-482a	3.3-1, 186	A
Tank (Unit 1 condensate storage tank)	Pressure boundary	Aluminum	Air – outdoor (external)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-756a	3.3-1, 227	A
Tank (Unit 1 condensate storage tank)	Pressure boundary	Aluminum	Air – outdoor (internal)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-482a	3.3-1, 186	A
Tank (Unit 1 condensate storage tank)	Pressure boundary	Aluminum	Air – outdoor (internal)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-756a	3.3-1, 227	A
Tank (Unit 1 condensate storage tank)	Pressure boundary	Aluminum	Concrete (external)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-482a	3.3-1, 186	A
Tank (Unit 1 condensate storage tank)	Pressure boundary	Aluminum	Concrete (external)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.I.A-755	3.3-1, 226	A
Tank (Unit 1 condensate storage tank)	Pressure boundary	Aluminum	Treated water (internal)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-413	3.3-1, 137	A
Tank (Unit 2 condensate storage tank)	Pressure boundary	Stainless steel	Air – outdoor (external)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-760a	3.3-1, 231	A

Table 3.3.2-1: Condensate Transfer and Storage 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**
Tank (Unit 2 condensate storage tank)	Pressure boundary	Stainless steel	Air – outdoor (external)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-757a	3.3-1, 228	A
Tank (Unit 2 condensate storage tank)	Pressure boundary	Stainless steel	Air – outdoor (internal)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-760a	3.3-1, 231	A
Tank (Unit 2 condensate storage tank)	Pressure boundary	Stainless steel	Air – outdoor (internal)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-757a	3.3-1, 228	A
Tank (Unit 2 condensate storage tank)	Pressure boundary	Stainless steel	Concrete (external)	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-759	3.3-1, 230	A
Tank (Unit 2 condensate storage tank)	Pressure boundary	Stainless steel	Concrete (external)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-758	3.3-1, 229	A
Tank (Unit 2 condensate storage tank)	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VII.H1.A-413	3.3-1, 137	A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A

Table 3.3.2-1: Condensate Transfer and Storage 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 (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Valve body	Pressure boundary	Cast austenitic stainless steel	Air – outdoor (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	Air – outdoor (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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Valve body	Pressure boundary	Stainless steel	Air – outdoor (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 – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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

1. Galvanized steel flanges are associated with the Unit 1 condensate storage tank.

Table 3.3.2-2: Control Rod Drive 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**
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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Bolting (Closure)	Mechanical closure	Carbon steel	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 steel	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	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Cylinder (N2)	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
Cylinder (N2)	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
Filter (CRD pump suction)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A

Table 3.3.2-2: Control Rod Drive 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
Filter (CRD pump suction)	Leakage boundary (spatial)	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
Filter (CRD pump suction)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Filter (Drive water)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Filter (Drive water)	Leakage boundary (spatial)	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
Filter (Drive water)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Flow nozzle	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Flow nozzle	Leakage boundary (spatial)	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
Flow nozzle	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Flow nozzle	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A

Table 3.3.2-2: Control Rod Drive 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 (CRD pump bearing cooler) shell	Leakage boundary (spatial)	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 pump bearing cooler) shell	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3-1, 098	A
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3-1, 222	A
Orifice	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A

Table 3.3.2-2: Control Rod Drive 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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Piping and 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 and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Piping and 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 and piping components	Pressure 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 and piping components	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A

Table 3.3.2-2: Control Rod Drive 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 and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Pump casing (Drive water)	Leakage boundary (spatial)	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 (Drive water)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Rupture disk	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
Rupture disk	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
Rupture disk	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Rupture disk	Pressure relief	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A

Table 3.3.2-2: Control Rod Drive 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**
Rupture disk	Pressure relief	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Rupture disk	Pressure relief	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A

Table 3.3.2-2: Control Rod Drive 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	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)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Valve body	Pressure boundary	Copper alloy	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	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.C2.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	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 3.3.2-3: Containment Atmosphere Cooling 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 (Drywell fan coil units) channel head	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (Drywell fan coil units) channel head	Pressure boundary	Copper alloy	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 (Drywell fan coil units) channel head	Pressure boundary	Copper alloy	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 (Drywell fan coil units) channel head	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Drywell fan coil units) tubes	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (Drywell fan coil units) tubes	Pressure boundary	Copper alloy	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 (Drywell fan coil units) tubes	Pressure boundary	Copper alloy	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 (Drywell fan coil units) tubes	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 is used to manage wall thinning due to erosion of components exposed to raw water within the scope of the GL 89-13 program.

Table 3.3.2-4: Control Building HVAC 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**
Accumulator (Control room 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 (Control room 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
Blower housing (Battery room emergency exhaust)	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 (Battery room emergency exhaust)	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 (Control room 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 (Control room 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
Blower housing (Control room booster 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 3.3.2-4: Control Building HVAC 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
Blower housing (Control room booster 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 (Control room 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 (Control room 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
Bolting (Closure)	Mechanical closure	Carbon steel	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 steel	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 steel	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 steel	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

Table 3.3.2-4: Control Building HVAC 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 (HVAC Closure)	Mechanical closure	Carbon steel	Air – outdoor (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 steel	Air – outdoor (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	Galvanized steel	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	Galvanized steel	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	Galvanized steel	Air – outdoor (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	Galvanized steel	Air – outdoor (external)	Loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3-1, 260	A
Drip pan	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-4: Control Building HVAC 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
Drip pan	Leakage boundary (spatial)	Copper alloy	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-272	3.3-1, 095	A
Drip pan	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.AP-209a	3.3-1, 004	A
Drip pan	Leakage boundary (spatial)	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
Drip pan	Leakage boundary (spatial)	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
Ducting and ducting components	Pressure boundary	Carbon steel	Air – indoor controlled (external)	None	None	VII.J.AP-2	3.3-1, 121	C
Ducting and ducting components	Pressure boundary	Carbon steel	Air – indoor controlled (internal)	None	None	VII.J.AP-2	3.3-1, 121	C
Ducting and ducting 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 ducting 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

Table 3.3.2-4: Control Building HVAC 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
Ducting and ducting 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
Ducting and ducting 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)	VIII.E.SP-59	3.4-1, 036	C
Ducting and ducting components	Pressure boundary	Galvanized steel	Air – indoor controlled (external)	None	None	V.F.EP-14	3.2-1, 059	A
Ducting and ducting components	Pressure boundary	Galvanized steel	Air – indoor controlled (internal)	None	None	V.F.EP-14	3.2-1, 059	A
Ducting and ducting components	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (external)	None	None	VII.J.AP-13	3.3-1, 116	C
Ducting and ducting components	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-13	3.3-1, 116	C
Ducting and ducting components	Pressure boundary	Galvanized 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
Ducting and ducting components	Pressure boundary	Galvanized steel	Air – outdoor (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-59	3.4-1, 036	C

Table 3.3.2-4: Control Building HVAC 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**
Flexible connection	Pressure boundary	Elastomer	Air – indoor controlled (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 controlled (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	Air – indoor controlled (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
Flexible connection	Pressure boundary	Elastomer	Air – indoor controlled (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
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

Table 3.3.2-4: Control Building HVAC 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**
Flexible connection	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
Flexible connection	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
Flexible connection	Pressure boundary	Elastomer	Air – outdoor (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 – outdoor (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	Air – outdoor (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
Flexible connection	Pressure boundary	Elastomer	Air – outdoor (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

Table 3.3.2-4: Control Building HVAC 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 (Control room A/C condenser unit) channel head with internal coating	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
Heat exchanger (Control room A/C condenser unit) channel head with internal coating	Pressure boundary	Gray cast iron	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 (Control room A/C condenser unit) channel head with internal coating	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
Heat exchanger (Control room A/C condenser unit) channel head with internal coating	Pressure boundary	Gray cast iron	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 (Control room A/C condenser unit) channel head with internal coating	Pressure boundary	Gray cast iron	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3-1, 038	A

Table 3.3.2-4: Control Building HVAC 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 (Control room A/C condenser unit) channel head with internal coating	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
Heat exchanger (Control room A/C condenser unit) channel head with internal coating	Pressure boundary	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Control room A/C condenser unit) fins	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.A-419	3.3-1, 096a	A
Heat exchanger (Control room A/C condenser unit) shell	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 (Control room A/C condenser unit) shell	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	C
Heat exchanger (Control room A/C condenser unit) tubes	Heat transfer	Copper alloy	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 (Control room A/C condenser unit) tubes	Pressure boundary	Copper alloy	Gas (external)	None	None	VII.J.AP-9	3.3-1, 114	C

Table 3.3.2-4: Control Building HVAC 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 (Control room A/C condenser unit) tubes	Pressure boundary	Copper alloy	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 (Control room A/C condenser unit) tubes	Pressure boundary	Copper alloy	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 (Control room A/C condenser unit) tubes	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Control room A/C condenser unit) tubesheet	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	C
Heat exchanger (Control room A/C condenser unit) tubesheet	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (Control room air handling unit cooling coil) fins	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.A-419	3.3-1, 096a	A
Heat exchanger (Control room air handling unit cooling coil) tubes	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.A-419	3.3-1, 096a	A

Table 3.3.2-4: Control Building HVAC 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 (Control room air handling unit cooling coil) tubes	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (Control room air handling unit cooling coil) tubes	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	C
Heat exchanger (Nonsafety-related coolers) tubes	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (Nonsafety-related coolers) tubes	Leakage boundary (spatial)	Copper alloy	Closed-cycle cooling water (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-203	3.3-1, 046	A
Piping and piping components	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Pressure boundary	Copper alloy	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 3.3.2-4: Control Building HVAC 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 and piping components	Leakage boundary (spatial)	Carbon steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3-1, 091	A
Piping and 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 and 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 and piping components	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping and 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 and 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 and piping components	Pressure boundary	Stainless steel	Air – indoor controlled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.AP-209a	3.3-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor controlled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.AP-221a	3.3-1, 006	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor controlled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.AP-209a	3.3-1, 004	A

Table 3.3.2-4: Control Building HVAC 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 and piping components	Pressure boundary	Stainless steel	Air – indoor controlled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.AP-221a	3.3-1, 006	A
Piping and 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 and 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 and 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 and 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
Thermowell	Pressure boundary	Stainless steel	Air – indoor controlled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.AP-209a	3.3-1, 004	A
Thermowell	Pressure boundary	Stainless steel	Air – indoor controlled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.AP-221a	3.3-1, 006	A
Thermowell	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
Thermowell	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
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

Table 3.3.2-4: Control Building HVAC 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	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	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	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – indoor controlled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	A
Valve body	Pressure boundary	Stainless steel	Air – indoor controlled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.AP-209a	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor controlled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.AP-221a	3.3-1, 006	A

Table 3.3.2-4: Control Building HVAC 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)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.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.F1.AP-221a	3.3-1, 006	A
Valve body	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
Valve body	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 aging management program 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) AMP is used to manage wall thinning due to erosion of components exposed to raw water within the scope of the GL 89-13 program.

Table 3.3.2-5: Demineralized Water Supply 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 steel	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 steel	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Piping and 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 and 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

Table 3.3.2-5: Demineralized Water Supply 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 and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 3.3.2-6: Drywell Pneumatic 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**
Accumulator (Air receiver)	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
Accumulator (Air receiver)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3-1, 004	A
Accumulator (Air receiver)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3-1, 006	A
Accumulator (Air receiver)	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Bolting (Closure)	Mechanical closure	Carbon steel	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 steel	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	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Filter housing	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
Filter 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

Table 3.3.2-6: Drywell Pneumatic 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
Filter housing	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
Filter housing	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
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3-1, 004	A
Filter housing	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3-1, 006	A
Filter housing	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Hose	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
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3-1, 004	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3-1, 006	A
Hose	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping and piping components	Leakage boundary (spatial)	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: Drywell Pneumatic 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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3-1, 091	A
Piping and 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 and 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 and piping components	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping and piping components	Pressure boundary	Copper alloy	Air – dry (internal)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A
Piping and piping components	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-6: Drywell Pneumatic 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 and piping components	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	A
Piping and 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 and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3-1, 006	A
Piping and piping components	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Valve body	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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 (spatial)	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	Carbon steel	Air – dry (internal)	Loss of material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-6: Drywell Pneumatic 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	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	Copper alloy	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	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	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-221a	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-209a	3.3-1, 006	A
Valve body	Pressure boundary	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 aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.3.2-7: Emergency Diesel Generators 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
Access hole cover	Shelter, protection	Carbon steel	Air – indoor uncontrolled (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	C
Access hole cover	Shelter, protection	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
Bolting (Closure)	Mechanical closure	Carbon steel	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 steel	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 steel	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 steel	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	Stainless steel	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Filter 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

Table 3.3.2-7: Emergency Diesel Generators 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
Filter housing	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
Filter housing	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	A
Filter housing	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Heat exchanger (Jacket water) channel head	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) channel head	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 (Jacket water) channel head	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) channel head	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 (Jacket water) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-7: Emergency Diesel Generators 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 (Jacket water) shell	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	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 (Jacket water) tubes	Heat transfer	Copper alloy	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	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	Closed-cycle cooling water (external)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-203	3.3-1, 046	A
Heat exchanger (Jacket water) tubes	Pressure boundary	Copper alloy	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	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Jacket water) tubes	Pressure boundary	Copper alloy	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) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Closed-cycle cooling water (external)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-203	3.3-1, 046	A
Heat exchanger (Jacket water) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Closed-cycle cooling water (external)	Loss of material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3-1, 072	A

Table 3.3.2-7: Emergency Diesel Generators 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 (Jacket water) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	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 (Jacket water) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	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) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	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) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Lube oil) channel head	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 (Lube oil) channel head	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 (Lube oil) channel head	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 (Lube oil) channel head	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 (Lube oil) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-7: Emergency Diesel Generators 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 (Lube oil) shell	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 (Lube oil) shell	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3-1, 098	A
Heat exchanger (Lube oil) tubes	Heat transfer	Copper alloy	Lubricating oil (external)	Reduction of heat transfer	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.C1.A-791	3.3-1, 257	A
Heat exchanger (Lube oil) tubes	Heat transfer	Copper alloy	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 (Lube oil) tubes	Pressure boundary	Copper alloy	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	C
Heat exchanger (Lube oil) tubes	Pressure boundary	Copper alloy	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 (Lube oil) tubes	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Lube oil) tubes	Pressure boundary	Copper alloy	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 3.3.2-7: Emergency Diesel Generators 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 (Lube oil) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	C
Heat exchanger (Lube oil) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	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 (Lube oil) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	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 (Lube oil) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3-1, 072	A
Heat exchanger (Lube oil) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Scavenging air) channel head	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 (Scavenging air) channel head	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 (Scavenging air) channel head	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

Table 3.3.2-7: Emergency Diesel Generators 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 (Scavenging air) channel head	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 (Scavenging air) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Scavenging air) shell	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 (Scavenging air) shell	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 (Scavenging air) tubes	Heat transfer	Copper alloy	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 (Scavenging air) tubes	Heat transfer	Copper alloy	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 (Scavenging air) tubes	Pressure boundary	Copper alloy	Closed-cycle cooling water (external)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-203	3.3-1, 046	A
Heat exchanger (Scavenging air) tubes	Pressure boundary	Copper alloy	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 (Scavenging air) tubes	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Scavenging air) tubes	Pressure boundary	Copper alloy	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 (Scavenging air) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Closed-cycle cooling water (external)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-203	3.3-1, 046	A

Table 3.3.2-7: Emergency Diesel Generators 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 (Scavenging air) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Closed-cycle cooling water (external)	Loss of material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3-1, 072	A
Heat exchanger (Scavenging air) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	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 (Scavenging air) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	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 (Scavenging air) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3-1, 072	A
Heat exchanger (Scavenging air) tubesheet with internal coating	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heater (Jacket water standby) housing	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
Heater (Jacket water standby) 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	C
Heater (Lube oil preheating) housing	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

Table 3.3.2-7: Emergency Diesel Generators 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**
Heater (Lube oil preheating) housing	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	C
Hose	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
Hose	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
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.AP-209a	3.3-1, 004	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.H2.AP-221a	3.3-1, 006	A
Hose	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-186	3.3-1, 043	A
Hose	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	A
Hose	Pressure boundary	Stainless steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	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	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 3.3.2-7: Emergency Diesel Generators 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	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.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.H2.AP-221a	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.AP-209a	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.H2.AP-221A	3.3-1, 006	A
Orifice	Throttle	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
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	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

Table 3.3.2-7: Emergency Diesel Generators 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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3-1, 091	A
Piping and 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 and 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.A.E-29	3.2-1, 044	A
Piping and 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 and 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
Piping and piping components	Pressure boundary	Carbon steel	Fuel oil (external)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	A

Table 3.3.2-7: Emergency Diesel Generators 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 and piping components	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	A
Piping and piping components	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Piping and piping components	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	A
Piping and 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 and piping components	Pressure boundary	Carbon steel	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.AP-194	3.3-1, 037	A
Piping and piping components	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and 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	B
Piping and 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	B
Piping and piping components	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Pressure boundary	Copper alloy	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

Table 3.3.2-7: Emergency Diesel Generators 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 and piping components	Pressure boundary	Copper alloy	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	A
Piping and piping components	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (external)	None	None	VII.J.AP-13	3.3-1, 116	A
Piping and piping components	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-13	3.3-1, 116	A
Piping and piping components	Pressure boundary	Galvanized steel	Air – outdoor (external)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4-1, 034	A
Piping and piping components	Pressure boundary	Galvanized 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 and 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 and 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 and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.AP-209a	3.3-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.H2.AP-221A	3.3-1, 006	A

Table 3.3.2-7: Emergency Diesel Generators 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 and piping components	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-186	3.3-1, 043	A
Piping and piping components	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	A
Piping and piping components	Pressure boundary	Stainless steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	A
Piping and piping components	Pressure boundary	Stainless steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Piping and 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
Piping and 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 and piping components	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping elements	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (external)	None	None	VII.J.AP-48	3.3-1, 117	A
Piping elements	Leakage boundary (spatial)	Glass	Waste water (internal)	None	None	VII.J.AP-277	3.3-1, 119	A
Piping elements	Pressure boundary	Glass	Air – indoor uncontrolled (external)	None	None	VII.J.AP-48	3.3-1, 117	A

Table 3.3.2-7: Emergency Diesel Generators 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 elements	Pressure boundary	Glass	Closed-cycle cooling water (internal)	None	None	VII.J.AP-166	3.3-1, 117	A
Pump casing (Air coolant jacket water)	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 (Air coolant jacket water)	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
Pump casing (Engine driven fuel 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 (Engine driven fuel oil)	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	A
Pump casing (Engine driven jacket water)	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 (Engine driven jacket water)	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
Pump casing (engine driven lube 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

Table 3.3.2-7: Emergency Diesel Generators 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 (engine driven lube oil)	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Pump casing (Fuel oil hand priming)	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 (Fuel oil hand priming)	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	A
Pump casing (Fuel oil transfer)	Pressure boundary	Carbon steel	Fuel oil (external)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	A
Pump casing (Fuel oil transfer)	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105	3.3-1, 070	A
Pump casing (Motor driven jacket water)	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 (Motor driven jacket water)	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 3.3.2-7: Emergency Diesel Generators 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 (Motor driven lube 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 (Motor driven lube oil)	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Pump casing (Prelube 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 (Prelube oil)	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Strainer (element)	Filter	Carbon steel	Lubricating oil (external)	Loss of material	Lubricating Oil Analysis (B.2.3.25) 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) One-Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	A
Tank (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

Table 3.3.2-7: Emergency Diesel Generators 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
Tank (Air receiver)	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
Tank (Clean fuel drain)	Leakage boundary (spatial)	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
Tank (Clean fuel drain)	Leakage boundary (spatial)	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
Tank (Clean fuel drain)	Leakage boundary (spatial)	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
Tank (Dirty fuel drain)	Leakage boundary (spatial)	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
Tank (Dirty fuel drain)	Leakage boundary (spatial)	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
Tank (Dirty fuel drain)	Leakage boundary (spatial)	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 3.3.2-7: Emergency Diesel Generators 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
Tank (Dirty fuel oil drain)	Leakage boundary (spatial)	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
Tank (Dirty fuel oil drain)	Leakage boundary (spatial)	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
Tank (Dirty fuel oil drain)	Leakage boundary (spatial)	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
Tank (Expansion)	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
Tank (Expansion)	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
Tank (Fuel oil day)	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
Tank (Fuel oil day)	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105a	3.3-1, 070	A

Table 3.3.2-7: Emergency Diesel Generators 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**
Tank (Fuel oil storage)	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
Tank (Fuel oil storage)	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-105a	3.3-1, 070	A
Tank (Fuel oil storage)	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	B
Tank (Fuel oil storage)	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	B
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	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 3.3.2-7: Emergency Diesel Generators 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 (spatial)	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	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	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
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	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.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) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	A
Valve body	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	A
Valve body	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

Table 3.3.2-7: Emergency Diesel Generators 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	Carbon steel	Raw water (internal)	Loss of material	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.AP-194	3.3-1, 037	A
Valve body	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	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	Pressure boundary	Copper alloy	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VI.CI.AP-133	3.3-1, 099	A
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	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% Zn	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	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	Pressure boundary	Copper alloy with greater than 15% Zn	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	Pressure boundary	Copper alloy with greater than 15% Zn	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3-1, 099	A

Table 3.3.2-7: Emergency Diesel Generators 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	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	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	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
Valve body	Pressure boundary	Gray cast iron	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3-1, 097	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
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	Stainless steel	Closed-cycle cooling water >140°F (internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-186	3.3-1, 043	A
Valve body	Pressure boundary	Stainless steel	Closed-cycle cooling water >140°F (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3-1, 049	A
Valve body	Pressure boundary	Stainless steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.H1.AP-136	3.3-1, 071	A

Table 3.3.2-7: Emergency Diesel Generators 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	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3-1, 100	A
Valve body	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
Valve body	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
Valve body	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 is used to manage wall thinning due to erosion of components exposed to raw water within the scope of the GL 89-13 program.

Table 3.3.2-8: Fire Protection 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 steel	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 steel	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 steel	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 steel	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 steel	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-241	3.3-1, 109	B
Bolting (Closure)	Mechanical closure	Carbon steel	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	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	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	Air – outdoor (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Expansion joint	Expansion/separation	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 joint	Expansion/separation	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 3.3.2-8: Fire Protection 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
Expansion joint	Expansion/separation	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 joint	Expansion/separation	Elastomer	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-75	3.3-1, 085	B
Expansion joint	Expansion/separation	Elastomer	Raw water (internal)	Hardening or loss of strength	Fire Water System (B.2.3.16)	VII.G.AP-75	3.3-1, 085	B
Expansion joint	Expansion/separation	Elastomer	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-76	3.3-1, 096	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	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
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	B
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
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	B

Table 3.3.2-8: Fire Protection 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	Gray cast iron	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
Fire hydrant	Pressure boundary	Gray cast 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	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
Fire hydrant	Pressure boundary	Gray cast 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	Gray cast 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	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Nozzle	Pressure boundary	Aluminum	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.A-451a	3.3-1, 189	A
Nozzle	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
Nozzle	Pressure boundary	Aluminum	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.A-451a	3.3-1, 189	A
Nozzle	Pressure boundary	Aluminum	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3-1, 131	B
Nozzle	Pressure boundary	Aluminum	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.A4.A-763a	3.3-1, 234	A
Nozzle	Pressure boundary	Aluminum	Gas (internal)	None	None	VII.J.AP-37	3.3-1, 113	A

Table 3.3.2-8: Fire Protection 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**
Nozzle	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Nozzle	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3-1, 131	B
Nozzle	Pressure boundary	Copper alloy with greater than 15% Zn	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	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
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	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
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
Orifice	Throttle	Stainless steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	Aluminum	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.A-451a	3.3-1, 189	A

Table 3.3.2-8: Fire Protection 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 and piping components	Leakage boundary (spatial)	Aluminum	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.A4.A-763a	3.3-1, 234	A
Piping and piping components	Leakage boundary (spatial)	Aluminum	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-180	3.3-1, 065	B
Piping and piping components	Leakage boundary (spatial)	Aluminum	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-180	3.3-1, 065	B
Piping and piping components	Leakage boundary (spatial)	Aluminum	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-8: Fire Protection 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 and piping components	Leakage boundary (spatial)	Copper alloy	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	Copper alloy	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	Copper alloy	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	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 and piping components	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	Ductile 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 and piping components	Leakage boundary (spatial)	Ductile iron	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B

Table 3.3.2-8: Fire Protection 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 and piping components	Leakage boundary (spatial)	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
Piping and piping components	Leakage boundary (spatial)	Ductile iron	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	Ductile iron	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Piping and piping components	Leakage boundary (spatial)	Ductile iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	Galvanized 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 and piping components	Leakage boundary (spatial)	Galvanized steel	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Galvanized steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	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 3.3.2-8: Fire Protection 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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	Malleable 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 and piping components	Leakage boundary (spatial)	Malleable iron	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	Malleable iron	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	Malleable 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 and piping components	Leakage boundary (spatial)	Malleable iron	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Leakage boundary (spatial)	Malleable iron	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A

Table 3.3.2-8: Fire Protection 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 and piping components	Leakage boundary (spatial)	Malleable iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Aluminum	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.A-451a	3.3-1, 189	A
Piping and piping components	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
Piping and piping components	Pressure boundary	Aluminum	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-180	3.3-1, 065	B
Piping and piping components	Pressure boundary	Aluminum	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-180	3.3-1, 065	B
Piping and piping components	Pressure boundary	Aluminum	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and 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 and 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 and piping components	Pressure boundary	Carbon steel	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-143	3.3-1, 089	B
Piping and piping components	Pressure boundary	Carbon steel	Air – outdoor (external)	Loss of material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3-1, 058	A

Table 3.3.2-8: Fire Protection 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 and 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 and piping components	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-234	3.3-1, 070	A
Piping and piping components	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping and 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 and 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 and 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
Piping and piping components	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and 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	B
Piping and 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	B
Piping and piping components	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-8: Fire Protection 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 and piping components	Pressure boundary	Copper alloy	Air – outdoor (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Pressure boundary	Copper alloy	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-132	3.3-1, 069	A
Piping and piping components	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	A
Piping and piping components	Pressure boundary	Copper alloy	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Piping and piping components	Pressure boundary	Copper alloy	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Piping and piping components	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Copper alloy	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-174	3.3-1, 108	B
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	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 and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-8: Fire Protection 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 and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Air – outdoor (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-132	3.3-1, 069	A
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-174	3.3-1, 108	B
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Soil (external)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-743	3.3-1, 214	A
Piping and piping components	Pressure boundary	Ductile 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 3.3.2-8: Fire Protection 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 and piping components	Pressure boundary	Ductile iron	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-143	3.3-1, 089	B
Piping and piping components	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
Piping and piping components	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
Piping and piping components	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
Piping and piping components	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
Piping and piping components	Pressure boundary	Ductile iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Ductile iron (with internal cement lining)	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
Piping and piping components	Pressure boundary	Ductile iron (with internal cement lining)	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 3.3.2-8: Fire Protection 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 and piping components	Pressure boundary	Ductile iron (with internal cement lining)	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Pressure boundary	Ductile iron (with internal cement lining)	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 and piping components	Pressure boundary	Ductile iron (with internal cement lining)	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Pressure boundary	Ductile iron (with internal cement lining)	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Piping and piping components	Pressure boundary	Ductile iron (with internal cement lining)	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 and piping components	Pressure boundary	Ductile iron (with internal cement lining)	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

Table 3.3.2-8: Fire Protection 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 and piping components	Pressure boundary	Ductile iron (with internal cement lining)	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Ductile iron (with internal cement lining)	Soil (external)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Piping and piping components	Pressure boundary	Ductile iron (with internal cement lining)	Soil (external)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3-1, 072	A
Piping and piping components	Pressure boundary	Ductile iron (with internal cement lining)	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Piping and piping components	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (external)	None	None	VII.J.AP-13	3.3-1, 116	A
Piping and piping components	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-143	3.3-1, 089	B
Piping and piping components	Pressure boundary	Galvanized steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping and 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 and 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

Table 3.3.2-8: Fire Protection 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 and 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 and piping components	Pressure boundary	Galvanized steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and 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 and piping components	Pressure boundary	Gray cast iron	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 and piping components	Pressure boundary	Gray cast iron	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-234	3.3-1, 070	A
Piping and 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 and 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 and 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 and 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 and piping components	Pressure boundary	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-8: Fire Protection 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 and piping components	Pressure boundary	Gray cast iron (with internal cement lining)	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Pressure boundary	Gray cast iron (with internal cement lining)	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 and piping components	Pressure boundary	Gray cast iron (with internal cement lining)	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Pressure boundary	Gray cast iron (with internal cement lining)	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Piping and piping components	Pressure boundary	Gray cast iron (with internal cement lining)	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Gray cast iron (with internal cement lining)	Soil (external)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Piping and piping components	Pressure boundary	Gray cast iron (with internal cement lining)	Soil (external)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3-1, 072	A

Table 3.3.2-8: Fire Protection 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 and piping components	Pressure boundary	Gray cast iron (with internal cement lining)	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3-1, 109	B
Piping and piping components	Pressure boundary	Malleable 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 and piping components	Pressure boundary	Malleable iron	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-143	3.3-1, 089	B
Piping and piping components	Pressure boundary	Malleable iron	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Pressure boundary	Malleable iron	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Pressure boundary	Malleable 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 and piping components	Pressure boundary	Malleable iron	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3-1, 064	B
Piping and piping components	Pressure boundary	Malleable iron	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3-1, 072	A
Piping and piping components	Pressure boundary	Malleable iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3-1, 004	A

Table 3.3.2-8: Fire Protection 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 and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3-1, 006	A
Piping and piping components	Pressure boundary	Stainless steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-136	3.3-1, 071	A
Pump casing (Electrical motor driven fire)	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 (Electrical motor driven fire)	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 (Electrical motor driven fire)	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
Pump casing (Electrical motor driven fire)	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 (Electrical motor driven fire)	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 (Electrical motor driven fire)	Pressure boundary	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-8: Fire Protection 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 (Engine driven fire)	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 (Engine driven fire)	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 (Engine driven fire)	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
Pump casing (Engine driven fire)	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 (Engine driven fire)	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 (Engine driven fire)	Pressure boundary	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing (Fire water jockey)	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 (Fire water jockey)	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 (Fire water jockey)	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
Pump casing (Fire water jockey)	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

Table 3.3.2-8: Fire Protection 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 (Fire water jockey)	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 water jockey)	Pressure boundary	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Leakage boundary (spatial)	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
Sprinkler	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Sprinkler	Leakage boundary (spatial)	Copper alloy	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Leakage boundary (spatial)	Copper alloy	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Leakage boundary (spatial)	Copper alloy	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Sprinkler	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B

Table 3.3.2-8: Fire Protection 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**
Sprinkler	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3-1, 004	A
Sprinkler	Leakage boundary (spatial)	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
Sprinkler	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	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
Sprinkler	Pressure boundary	Carbon steel	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Carbon steel	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	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

Table 3.3.2-8: Fire Protection 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**
Sprinkler	Pressure boundary	Carbon steel	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Carbon steel	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Sprinkler	Pressure boundary	Copper alloy	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Copper alloy	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Copper alloy	Air – outdoor (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Sprinkler	Pressure boundary	Copper alloy	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Copper alloy	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Sprinkler	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B

Table 3.3.2-8: Fire Protection 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**
Sprinkler	Pressure boundary	Copper alloy with greater than 15% Zn	Air – outdoor (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Sprinkler	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	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
Sprinkler	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
Sprinkler	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Stainless steel	Air – outdoor (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3-1, 004	A
Sprinkler	Pressure boundary	Stainless steel	Air – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3-1, 006	A

Table 3.3.2-8: Fire Protection 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
Sprinkler	Pressure boundary	Stainless steel	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Stainless steel	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Spray	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
Sprinkler	Spray	Carbon steel	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Carbon steel	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Carbon steel	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Carbon steel	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Carbon steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Spray	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Sprinkler	Spray	Copper alloy	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Copper alloy	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Copper alloy	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B

Table 3.3.2-8: Fire Protection 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**
Sprinkler	Spray	Copper alloy	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Copper alloy	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Spray	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A
Sprinkler	Spray	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Copper alloy with greater than 15% Zn	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Copper alloy with greater than 15% Zn	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Sprinkler	Spray	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3-1, 004	A
Sprinkler	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

Table 3.3.2-8: Fire Protection 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**
Sprinkler	Spray	Stainless steel	Air – indoor uncontrolled (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Stainless steel	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Stainless steel	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3-1, 130	B
Sprinkler	Spray	Stainless steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer (element)	Filter	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3-1, 004	A
Strainer (element)	Filter	Stainless steel	Air – indoor uncontrolled (internal)	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 (internal)	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 (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-55	3.3-1, 066	B
Strainer (element)	Filter	Stainless steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Tank (Carbon dioxide storage)	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
Tank (Carbon dioxide storage)	Pressure boundary	Carbon steel	Air – outdoor (external)	Loss of material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3-1, 058	A
Tank (Carbon dioxide storage)	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A

Table 3.3.2-8: Fire Protection 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**
Tank (Fire protection storage) with internal coating	Pressure boundary	Carbon steel	Air – outdoor (external)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	B
Tank (Fire protection storage) with internal coating	Pressure boundary	Carbon steel	Air – outdoor (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	B
Tank (Fire protection storage) with internal coating	Pressure boundary	Carbon steel	Concrete (external)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	B
Tank (Fire protection storage) with internal coating	Pressure boundary	Carbon steel	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.E4.A-416	3.3-1, 138	A
Tank (Fire protection storage) with internal coating	Pressure boundary	Carbon steel	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3-1, 136	B
Tank (Fuel oil)	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
Tank (Fuel oil)	Pressure boundary	Carbon steel	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-234	3.3-1, 070	A
Valve body	Leakage boundary (spatial)	Aluminum	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.A-451a	3.3-1, 189	A

Table 3.3.2-8: Fire Protection 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 (spatial)	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	Leakage boundary (spatial)	Aluminum	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-180	3.3-1, 065	B
Valve body	Leakage boundary (spatial)	Aluminum	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-180	3.3-1, 065	B
Valve body	Leakage boundary (spatial)	Aluminum	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	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 (spatial)	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	Leakage boundary (spatial)	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	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Leakage boundary (spatial)	Copper alloy	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Valve body	Leakage boundary (spatial)	Copper alloy	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 (spatial)	Copper alloy	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-8: Fire Protection 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 (spatial)	Copper alloy with greater than 15% Zn	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 (spatial)	Copper alloy with greater than 15% Zn	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3-1, 064	B
Valve body	Leakage boundary (spatial)	Copper alloy with greater than 15% Zn	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 (spatial)	Copper alloy with greater than 15% Zn	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	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 (spatial)	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	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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	Leakage boundary (spatial)	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Aluminum	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.A-451a	3.3-1, 189	A

Table 3.3.2-8: Fire Protection 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	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	Raw water (internal)	Flow blockage	Fire Water System (B.2.3.16)	VII.G.AP-180	3.3-1, 065	B
Valve body	Pressure boundary	Aluminum	Raw water (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-180	3.3-1, 065	B
Valve body	Pressure boundary	Aluminum	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
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	Air – indoor uncontrolled (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	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
Valve body	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
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)	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	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-8: Fire Protection 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	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – outdoor (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-132	3.3-1, 069	A
Valve body	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	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	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	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	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% Zn	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	Air – outdoor (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4-1, 106	A

Table 3.3.2-8: Fire Protection 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% Zn	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-132	3.3-1, 069	A
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	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% Zn	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% Zn	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	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	Air – indoor uncontrolled (internal)	Loss of material	Fire Water System (B.2.3.16)	VII.G.AP-143	3.3-1, 089	B
Valve body	Pressure boundary	Gray cast iron	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
Valve body	Pressure boundary	Gray cast iron	Fuel oil (internal)	Loss of material	Fuel Oil Chemistry (B.2.3.18) One-Time Inspection (B.2.3.20)	VII.G.AP-234	3.3-1, 070	A

Table 3.3.2-8: Fire Protection 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	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	Raw water (internal)	Wall thinning - erosion	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3-1, 126	E, 1
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	B
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	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	B

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 Fire Water System (B.2.3.16) AMP is used to manage wall thinning due to erosion of components in the fire protection system.

Table 3.3.2-9: Fuel Pool Cooling and Cleanup 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 steel	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 steel	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	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	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	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) channel head	Leakage boundary (spatial)	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 (Fuel pool) channel head	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.A-770a	3.3-1, 241	A
Heat exchanger (Fuel pool) channel head	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-111	3.3-1, 203	B A
Heat exchanger (Fuel pool) shell	Leakage boundary (spatial)	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 (Fuel pool) shell	Leakage boundary (spatial)	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

Table 3.3.2-9: Fuel Pool Cooling and Cleanup 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	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Orifice	Leakage boundary (spatial)	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	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B A
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.E4.AP-221a	3.3-1, 006	A
Orifice	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B A
Orifice	Throttle	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B A
Piping and piping components	Leakage boundary (spatial)	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 3.3.2-9: Fuel Pool Cooling and Cleanup 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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B A
Piping and 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 and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Piping and 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 and 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

Table 3.3.2-9: Fuel Pool Cooling and Cleanup 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 and piping components	Pressure boundary	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B A
Pump casing (Fuel pool holding)	Leakage boundary (spatial)	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 (Fuel pool holding)	Leakage boundary (spatial)	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 (Fuel pool holding)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B A
Pump casing (Fuel pool/cooling)	Leakage boundary (spatial)	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 (Fuel pool/cooling)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Pump casing (Precoat)	Leakage boundary (spatial)	Ductile 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 (Precoat)	Leakage boundary (spatial)	Ductile iron	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A

Table 3.3.2-9: Fuel Pool Cooling and Cleanup 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 (Precoat)	Leakage boundary (spatial)	Ductile iron	Treated water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.A4.AP-31	3.3-1, 072	A
Tank (Fuel pool f/d precoat) with internal coating	Leakage boundary (spatial)	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
Tank (Fuel pool f/d precoat) with internal coating	Leakage boundary (spatial)	Carbon steel	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
Tank (Fuel pool f/d precoat) with internal coating	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Tank (Fuel pool filter demineralizer)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Tank (Fuel pool filter demineralizer)	Leakage boundary (spatial)	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
Tank (Fuel pool filter demineralizer)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B A
Tank (Skimmer surge)	Leakage boundary (spatial)	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 3.3.2-9: Fuel Pool Cooling and Cleanup 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**
Tank (Skimmer surge)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A

Table 3.3.2-9: Fuel Pool Cooling and Cleanup 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)	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	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3-1, 203	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 3.3.2-10: Instrument Air 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**
Accumulator (Air receiver)	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
Accumulator (Air receiver)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3-1, 004	A
Accumulator (Air receiver)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3-1, 006	A
Accumulator (Air receiver)	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Bolting (Closure)	Mechanical closure	Carbon steel	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 steel	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	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Hose	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
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3-1, 004	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3-1, 006	A

Table 3.3.2-10: Instrument Air 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**
Hose	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping and 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 and 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 and piping components	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
Piping and piping components	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Pressure boundary	Copper alloy	Gas (internal)	None	None	VII.J.AP-9	3.3-1, 114	A
Piping and 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 and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3-1, 006	A
Piping and piping components	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Pressure regulator	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
Pressure regulator	Pressure boundary	Carbon steel	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A

Table 3.3.2-10: Instrument Air 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	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	Gas (internal)	None	None	VII.J.AP-6	3.3-1, 121	A
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	Gas (internal)	None	None	VII.J.AP-9	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-221a	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-209a	3.3-1, 006	A
Valve body	Pressure boundary	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 aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. 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

None

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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)	VII.I.A-03	3.3-1, 012	A
Bolting (Closure)	Mechanical closure	Carbon steel	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	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	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	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 (spatial)	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 (spatial)	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 (spatial)	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	C
Fan housing (Vapor extractor)	Leakage boundary (spatial)	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 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fan housing (Vapor extractor)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Filter housing (Fuller's earth)	Leakage boundary (spatial)	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
Filter housing (Fuller's earth)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Filter housing (PD pump suction)	Leakage boundary (spatial)	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
Filter housing (PD pump suction)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Heat exchanger (Chillers) shell	Leakage boundary (spatial)	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 (Chillers) shell	Leakage boundary (spatial)	Carbon steel	Closed-cycle cooling water (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E4.AP-189	3.3-1, 046	A

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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	Leakage boundary (spatial)	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 (Condenser) shell	Leakage boundary (spatial)	Carbon steel	Closed-cycle cooling water (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E4.AP-189	3.3-1, 046	A
Heat exchanger (Decay heat removal) shell	Leakage boundary (spatial)	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 (Decay heat removal) shell	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.A-770a	3.3-1, 241	A
Heat exchanger (Decay heat removal) shell	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A4.AP-111	3.3-1, 203	B A
Heat exchanger (EHC fluid cooler) shell	Leakage boundary (spatial)	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 (EHC fluid cooler) shell	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.A-770a	3.3-1, 241	A
Heat exchanger (EHC fluid cooler) shell	Leakage boundary (spatial)	Stainless steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.C1.AP-138	3.3-1, 100	C
Heat exchanger (Evaporator) shell	Leakage boundary (spatial)	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

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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 (Evaporator) shell	Leakage boundary (spatial)	Carbon steel	Closed-cycle cooling water (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E4.AP-189	3.3-1, 046	A
Heat exchanger (Hot water) shell	Leakage boundary (spatial)	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 (Hot water) shell	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	D C
Heat exchanger (Lube oil cooler) shell	Leakage boundary (spatial)	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 (Lube oil cooler) shell	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.H2.AP-152a	3.3-1, 098	A
Heat exchanger (Oil cooler) shell	Leakage boundary (spatial)	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 (Oil cooler) shell	Leakage boundary (spatial)	Carbon steel	Closed-cycle cooling water (internal)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.E4.AP-189	3.3-1, 046	A

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Hose	Leakage boundary (spatial)	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
Hose	Leakage boundary (spatial)	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
Orifice	Leakage boundary (spatial)	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	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Lubricating oil (waste oil) (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.G.AP-117	3.3-1, 250	A

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3-1, 091	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-95	3.4-1, 044	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Pump casing (Chilled water)	Leakage boundary (spatial)	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: Non-Safety Affecting Safety-Related Systems – Summary 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 (Chilled water)	Leakage boundary (spatial)	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
Pump casing (Condenser circulating water)	Leakage boundary (spatial)	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 (Condenser circulating water)	Leakage boundary (spatial)	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
Pump casing (Control building equipment drain sump)	Leakage boundary (spatial)	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 (Control building equipment drain sump)	Leakage boundary (spatial)	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 (Control building equipment drain sump)	Leakage boundary (spatial)	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 (Control building floor drain sump)	Leakage boundary (spatial)	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 (Control building floor drain sump)	Leakage boundary (spatial)	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 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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 (Control building floor drain sump)	Leakage boundary (spatial)	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 (Control building non-radioactive sump)	Leakage boundary (spatial)	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 (Control building non-radioactive sump)	Leakage boundary (spatial)	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 (Control building non-radioactive sump)	Leakage boundary (spatial)	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 (DHR primary side)	Leakage boundary (spatial)	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 (DHR primary side)	Leakage boundary (spatial)	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 (DHR primary side)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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 (EHC PD)	Leakage boundary (spatial)	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 (EHC PD)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Pump casing (Hot water circulation)	Leakage boundary (spatial)	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 (Hot water circulation)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Pump casing (Hot water system chemical addition)	Leakage boundary (spatial)	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 (Hot water system chemical addition)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Pump casing (Lube oil condenser vapor extractor)	Leakage boundary (spatial)	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 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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 (Lube oil condenser vapor extractor)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Pump casing (Lube oil transfer)	Leakage boundary (spatial)	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 (Lube oil transfer)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Pump casing (Main turbine lube oil vapor extractor)	Leakage boundary (spatial)	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 turbine lube oil vapor extractor)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Pump casing (Primary hot water recirculation)	Leakage boundary (spatial)	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 (Primary hot water recirculation)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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 (Radwaste and radwaste addition building hot water circulating)	Leakage boundary (spatial)	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 (Radwaste and radwaste addition building hot water circulating)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Pump casing (Reactor building hot water secondary recirculating)	Leakage boundary (spatial)	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 hot water secondary recirculating)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Pump casing (Sewage ejector 1A&1B)	Leakage boundary (spatial)	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 (Sewage ejector 1A&1B)	Leakage boundary (spatial)	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 (Sewage ejector 1A&1B)	Leakage boundary (spatial)	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 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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 and control building hot water secondary recirculating)	Leakage boundary (spatial)	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 and control building hot water secondary recirculating)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Pump casing (Turbine lube oil storage transfer)	Leakage boundary (spatial)	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 lube oil storage transfer)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Pump casing (Turbine oil transfer)	Leakage boundary (spatial)	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 oil transfer)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Rupture disk	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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 disk	Leakage boundary (spatial)	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
Rupture disk	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Sight glass	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (external)	None	None	VII.J.AP-48	3.3-1, 117	A
Sight glass	Leakage boundary (spatial)	Glass	Lubricating oil (internal)	None	None	VII.J.AP-15	3.3-1, 117	A
Sight glass	Leakage boundary (spatial)	Glass	Treated water (internal)	None	None	VII.J.AP-51	3.3-1, 117	A
Tank (Air dryer)	Leakage boundary (spatial)	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
Tank (Air dryer)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Tank (Air separator)	Leakage boundary (spatial)	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
Tank (Air separator)	Leakage boundary (spatial)	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

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (Collection tank)	Leakage boundary (spatial)	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
Tank (Collection tank)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4-1, 012	B A
Tank (EHC oil reservoir)	Leakage boundary (spatial)	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
Tank (EHC oil reservoir)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Tank (Expansion tank)	Leakage boundary (spatial)	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
Tank (Expansion tank)	Leakage boundary (spatial)	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
Tank (Hot water system air separator)	Leakage boundary (spatial)	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 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (Hot water system air separator)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4-1, 012	B A
Tank (Hot water system chemical addition)	Leakage boundary (spatial)	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
Tank (Hot water system chemical addition)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4-1, 012	B A
Tank (Hot water system expansion)	Leakage boundary (spatial)	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
Tank (Hot water system expansion)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4-1, 012	B A
Tank (Main turbine oil conditioner)	Leakage boundary (spatial)	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
Tank (Main turbine oil conditioner)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (Oil storage)	Leakage boundary (spatial)	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
Tank (Oil storage)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Tank (Refueling floor vent drain pots)	Leakage boundary (spatial)	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
Tank (Refueling floor vent drain pots)	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Tank (Turbine oil reservoir)	Leakage boundary (spatial)	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
Tank (Turbine oil reservoir)	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Tank (Water heater)	Leakage boundary (spatial)	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: Non-Safety Affecting Safety-Related Systems – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank (Water heater)	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	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
Valve body	Leakage boundary (spatial)	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VIII.G.SP-91	3.4-1, 040	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-11: Non-Safety Affecting Safety-Related Systems – Summary 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 (spatial)	Copper alloy	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-140	3.3-1, 022	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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. 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

None

Table 3.3.2-12: Primary Containment Chilled Water System (Unit 2 Only) – Summary 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)	VII.I.A-03	3.3-1, 012	A
Bolting (Closure)	Mechanical closure	Carbon steel	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger (Condenser) channel head	Leakage boundary (spatial)	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) channel head	Leakage boundary (spatial)	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
Heat exchanger (Condenser) channel head	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Condenser) shell	Leakage boundary (spatial)	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) shell	Leakage boundary (spatial)	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, 2

Table 3.3.2-12: Primary Containment Chilled Water System (Unit 2 Only) – Summary 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 (Evaporator) channel head	Leakage boundary (spatial)	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 (Evaporator) channel head	Leakage boundary (spatial)	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 (Evaporator) shell	Leakage boundary (spatial)	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 (Evaporator) shell	Leakage boundary (spatial)	Carbon steel	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, 3
Heat exchanger (Primary containment cooling units) return bends	Pressure boundary	Copper alloy with greater than 15% Zn	Air – indoor uncontrolled (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3-1, 132	C
Heat exchanger (Primary containment cooling units) return bends	Pressure boundary	Copper alloy with greater than 15% Zn	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 (Primary containment cooling units) return bends	Pressure boundary	Copper alloy with greater than 15% Zn	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

Table 3.3.2-12: Primary Containment Chilled Water System (Unit 2 Only) – Summary 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 cooling units) return bends	Pressure boundary	Copper alloy with greater than 15% Zn	Closed-cycle cooling water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.AP-43	3.3-1, 072	A
Heat exchanger (Primary containment cooling units) tubes	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (Primary containment cooling units) tubes	Pressure boundary	Copper alloy	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 3.3.2-12: Primary Containment Chilled Water System (Unit 2 Only) – Summary 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	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 and 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
Piping and piping components	Pressure 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 and piping components	Pressure 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 and piping components	Pressure 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 elements	Leakage boundary (spatial)	Glass	Air – indoor uncontrolled (external)	None	None	VII.J.AP-48	3.3-1, 117	A
Piping elements	Leakage boundary (spatial)	Glass	Closed-cycle cooling water (internal)	None	None	VII.J.AP-166	3.3-1, 117	A
Pump casing (Chemical feed)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Pump casing (Chemical feed)	Leakage boundary (spatial)	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
Pump casing (Chemical feed)	Leakage boundary (spatial)	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 3.3.2-12: Primary Containment Chilled Water System (Unit 2 Only) – Summary 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 (Chilled water)	Leakage boundary (spatial)	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 (Chilled water)	Leakage boundary (spatial)	Gray cast iron	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 (Chilled water)	Leakage boundary (spatial)	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
Tank (Chemical addition tank)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Tank (Chemical addition tank)	Leakage boundary (spatial)	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
Tank (Chemical addition tank)	Leakage boundary (spatial)	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
Tank (Expansion tank)	Leakage boundary (spatial)	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
Tank (Expansion tank)	Leakage boundary (spatial)	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
Thermowell	Leakage boundary (spatial)	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
Thermowell	Pressure 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 3.3.2-12: Primary Containment Chilled Water System (Unit 2 Only) – Summary 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 (spatial)	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 (spatial)	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
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.F1.AP-202	3.3-1, 045	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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) AMP is used to manage the wall thinning due to erosion aging effect.
2. As an outermost component of the condenser, the shell is credited as a leakage boundary for the heat exchanger assembly. The internal environment for the condenser shell is conservatively listed as raw water (the primary side fluid in the heat exchanger); however, because the normal environment on the inside of the shell is refrigerant gas, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is credited for management of the internal surface of the condenser shell.
3. As an outermost component of the evaporator, the shell is credited as a leakage boundary for the heat exchanger assembly. The internal environment for the evaporator shell is conservatively listed as closed cycle cooling water (the primary side fluid in the heat exchanger); however, because the normal environment on the inside of the shell is refrigerant gas, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is credited for management of the internal surface of the evaporator shell.

Table 3.3.2-13: Process Radiation Monitoring 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 steel	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 steel	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.AP-209a	3.3-1, 004	A
Hose	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
Hose	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
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3-1, 006	A
Piping and piping components	Pressure 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 and 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 and 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 and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (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	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.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

Table 3.3.2-13: Process Radiation Monitoring 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 (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.AP-209a	3.3-1, 004	A
Valve body	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3-1, 006	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.3.2-14: Radwaste 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 steel	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 steel	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	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger (Drain sump) channel head with internal coating	Leakage boundary (spatial)	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 (Drain sump) channel head with internal coating	Leakage boundary (spatial)	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 (Drain sump) channel head with internal coating	Leakage boundary (spatial)	Carbon steel	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 3.3.2-14: Radwaste 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 (Drain sump) channel head with internal coating	Leakage boundary (spatial)	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
Heat exchanger (Drain sump) shell	Leakage boundary (spatial)	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 (Drain sump) shell	Leakage boundary (spatial)	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
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Orifice	Leakage boundary (spatial)	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	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 3.3.2-14: Radwaste 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 and piping components	Leakage boundary (spatial)	Carbon steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3-1, 091	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3-1, 095	A
Piping and 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 and 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 and 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

Table 3.3.2-14: Radwaste 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 and 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 (Cleanup decant)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Pump casing (Cleanup decant)	Leakage boundary (spatial)	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
Pump casing (Cleanup decant)	Leakage boundary (spatial)	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
Pump casing (Cleanup sludge discharge mix)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Pump casing (Cleanup sludge discharge mix)	Leakage boundary (spatial)	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
Pump casing (Cleanup sludge discharge mix)	Leakage boundary (spatial)	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
Pump casing (Reactor building equipment drain)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A

Table 3.3.2-14: Radwaste 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 (Reactor building equipment drain)	Leakage boundary (spatial)	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
Pump casing (Reactor building equipment drain)	Leakage boundary (spatial)	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
Pump casing (Reactor building floor drain)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Pump casing (Reactor building floor drain)	Leakage boundary (spatial)	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
Pump casing (Reactor building floor drain)	Leakage boundary (spatial)	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
Tank (Cation floc & measuring)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Tank (Cation floc & measuring)	Leakage boundary (spatial)	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 3.3.2-14: Radwaste 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
Tank (Cation floc & measuring)	Leakage boundary (spatial)	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
Tank (Cleanup phase separators)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Tank (Cleanup phase separators)	Leakage boundary (spatial)	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
Tank (Cleanup phase separators)	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A

Table 3.3.2-14: Radwaste 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 (spatial)	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 (spatial)	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	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

General Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant Specific Notes

None

Table 3.3.2-15: Reactor Building Closed Cooling Water 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 steel	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 steel	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	Low alloy steel	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	Low alloy steel	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	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Compressor housing (Drywell pneumatic)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Compressor housing (Drywell pneumatic)	Leakage boundary (spatial)	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
Compressor housing (Drywell pneumatic)	Leakage boundary (spatial)	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
Heat exchanger (Drywell pneumatic after cooler) shell	Leakage boundary (spatial)	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 3.3.2-15: Reactor Building Closed Cooling Water 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 (Drywell pneumatic after cooler) shell	Leakage boundary (spatial)	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	C
Heat exchanger (Drywell sump cooler) shell	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 (Drywell sump cooler) shell	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	C
Hose	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Hose	Pressure 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
Hose	Pressure 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
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Orifice	Leakage boundary (spatial)	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
Orifice	Leakage boundary (spatial)	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
Orifice	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.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.C2.AP-221a	3.3-1, 006	A

Table 3.3.2-15: Reactor Building Closed Cooling Water 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	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
Orifice	Throttle	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A

Table 3.3.2-15: Reactor Building Closed Cooling Water 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 and 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 and 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
Piping and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	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 and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	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 and piping components	Pressure boundary	Copper alloy with greater than 15% Zn	Closed-cycle cooling water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.C2.AP-43	3.3-1, 072	A
Piping and piping components	Pressure 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 and piping components	Pressure 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 and piping components	Pressure 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
Pump casing (RBCCW chem add)	Leakage boundary (spatial)	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 3.3.2-15: Reactor Building Closed Cooling Water 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 (RBCCW chem add)	Leakage boundary (spatial)	Gray cast iron	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 (RBCCW chem add)	Leakage boundary (spatial)	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
Tank (RBCCW chem add)	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Tank (RBCCW chem add)	Leakage boundary (spatial)	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
Tank (RBCCW chem add)	Leakage boundary (spatial)	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
Tank (RBCCW surge)	Leakage boundary (spatial)	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
Tank (RBCCW surge)	Leakage boundary (spatial)	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
Thermowell	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A
Thermowell	Leakage boundary (spatial)	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
Thermowell	Leakage boundary (spatial)	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
Thermowell	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3-1, 004	A

Table 3.3.2-15: Reactor Building Closed Cooling Water 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**
Thermowell	Pressure 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
Thermowell	Pressure 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 (spatial)	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 (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A

Table 3.3.2-15: Reactor Building Closed Cooling Water 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	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
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	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% Zn	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	Pressure boundary	Copper alloy with greater than 15% Zn	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	Pressure 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	Pressure 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	Pressure 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

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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. 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

None

Table 3.3.2-16: Reactor Building HVAC 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 steel	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 steel	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 steel	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 steel	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
Drip pan	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.A-781a	3.3-1, 094a	C
Drip pan	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.AP-99a	3.3-1, 094	C
Drip pan	Leakage boundary (spatial)	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
Ducting and ducting 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 3.3.2-16: Reactor Building HVAC 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
Ducting and ducting 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 ducting 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
Ducting and ducting 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 ducting 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	C
Ducting and ducting 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.G.AP-76	3.3-1, 096	C
Ducting and ducting components	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (external)	None	None	VII.J.AP-13	3.3-1, 116	C
Ducting and ducting components	Pressure boundary	Galvanized steel	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-13	3.3-1, 116	C

Table 3.3.2-16: Reactor Building HVAC 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**
Ducting and ducting components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.A-781a	3.3-1, 094a	A
Ducting and ducting components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.AP-99a	3.3-1, 094	A
Ducting and ducting components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.A-781a	3.3-1, 094a	A
Ducting and ducting components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.AP-99a	3.3-1, 094	A
Fan housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.A-451a	3.3-1, 189	A
Fan housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.A-763a	3.3-1, 234	A
Fan housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.A-451a	3.3-1, 189	A
Fan housing	Pressure boundary	Aluminum	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.A-763a	3.3-1, 234	A
Fan housing	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
Fan housing	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 3.3.2-16: Reactor Building HVAC 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 (Core spray and RHR pump room cooler) channel head	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 (Core spray and RHR pump room cooler) channel head	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 (Core spray and RHR pump room cooler) channel head	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 (Core spray and RHR pump room cooler) channel head	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 (Core spray and RHR pump room cooler) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Core spray and RHR pump room cooler) fins	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F4.A-419	3.3-1, 096a	A

Table 3.3.2-16: Reactor Building HVAC 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 (Core spray and RHR pump room cooler) tubes	Heat transfer	Stainless steel	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (Core spray and RHR pump room cooler) tubes	Heat transfer	Stainless steel	Raw water (internal)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.E-21	3.2-1, 027	A
Heat exchanger (Core spray and RHR pump room cooler) tubes	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
Heat exchanger (Core spray and RHR pump room cooler) tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.A-770a	3.3-1, 241	A
Heat exchanger (Core spray and RHR pump room cooler) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Heat exchanger (Core spray and RHR pump room 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	3.2-1, 025	A
Heat exchanger (Core spray and RHR pump room cooler) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-16: Reactor Building HVAC 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 (CRD pump room cooler) channel head	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (CRD pump room cooler) channel head	Pressure boundary	Copper alloy	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 (CRD pump room cooler) channel head	Pressure boundary	Copper alloy	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 (CRD pump room cooler) channel head	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (CRD pump room cooler) fins	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-419	3.3-1, 096a	A
Heat exchanger (CRD pump room cooler) tubes	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (CRD pump room cooler) tubes	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (CRD pump room cooler) tubes	Pressure boundary	Copper alloy	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3-1, 038	A

Table 3.3.2-16: Reactor Building HVAC 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 (CRD pump room cooler) tubes	Pressure boundary	Copper alloy	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 (CRD pump room cooler) tubes	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Hot water coils) tubes	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (Hot water coils) tubes	Leakage boundary (spatial)	Copper alloy	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-140	3.3-1, 022	D C
Heat exchanger (HPCI room cooler) channel head	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 room cooler) channel head	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 (HPCI room cooler) channel head	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 (HPCI room cooler) channel head	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

Table 3.3.2-16: Reactor Building HVAC 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 (HPCI room cooler) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (HPCI room cooler) fins	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-419	3.3-1, 096a	A
Heat exchanger (HPCI room cooler) tubes	Heat transfer	Stainless steel	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (HPCI room cooler) tubes	Heat transfer	Stainless steel	Raw water (internal)	Reduction of heat transfer	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.E-21	3.2-1, 027	A
Heat exchanger (HPCI room cooler) tubes	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
Heat exchanger (HPCI room cooler) tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.A-770a	3.3-1, 241	A
Heat exchanger (HPCI room cooler) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Flow blockage	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.2-1, 025	A
Heat exchanger (HPCI room 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	3.2-1, 025	A
Heat exchanger (HPCI room cooler) tubes	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-16: Reactor Building HVAC 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 (Nonsafety-related coolers) tubes	Leakage boundary (spatial)	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Heat exchanger (Nonsafety-related coolers) tubes	Leakage boundary (spatial)	Copper alloy	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 (RCIC pump room cooler) channel head	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 (RCIC pump room cooler) channel head	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 (RCIC pump room cooler) channel head	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 (RCIC pump room cooler) channel head	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 (RCIC pump room cooler) channel head	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (RCIC pump room cooler) fins	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F4.A-419	3.3-1, 096a	A

Table 3.3.2-16: Reactor Building HVAC 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 (RCIC pump room cooler) tubes	Heat transfer	Copper alloy	Air – indoor uncontrolled (external)	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F4.A-419	3.3-1, 096a	A
Heat exchanger (RCIC pump room cooler) tubes	Heat transfer	Copper alloy	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 (RCIC pump room cooler) tubes	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	C
Heat exchanger (RCIC pump room cooler) tubes	Pressure boundary	Copper alloy	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 (RCIC pump room cooler) tubes	Pressure boundary	Copper alloy	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 (RCIC pump room cooler) tubes	Pressure boundary	Copper alloy	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	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
Piping and piping components	Leakage boundary (spatial)	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 3.3.2-16: Reactor Building HVAC 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 and piping components	Leakage boundary (spatial)	Carbon steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3-1, 091	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Waste water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3-1, 095	A
Piping and piping components	Pressure boundary	Copper alloy	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and piping components	Pressure boundary	Copper alloy	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A
Piping and 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 and 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 and 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 and 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

Table 3.3.2-16: Reactor Building HVAC 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 (spatial)	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 (spatial)	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 (spatial)	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	Air – indoor uncontrolled (external)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	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% Zn	Air – indoor uncontrolled (internal)	None	None	VII.J.AP-144	3.3-1, 114	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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.
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 Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage wall thinning due to erosion of components exposed to raw water within the scope of the GL 89-13 program.

Table 3.3.2-17: Reactor Water Cleanup 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 steel	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 steel	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	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger (RWCU non-regenerative) channel head	Leakage boundary (spatial)	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 (RWCU non-regenerative) channel head	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	D C
Heat exchanger (RWCU non-regenerative) shell	Leakage boundary (spatial)	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 (RWCU non-regenerative) shell	Leakage boundary (spatial)	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

Table 3.3.2-17: Reactor Water Cleanup 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 (RWCU pump cooler) channel head	Leakage boundary (spatial)	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 (RWCU pump cooler) channel head	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	D C
Heat exchanger (RWCU pump cooler) shell	Leakage boundary (spatial)	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 (RWCU pump cooler) shell	Leakage boundary (spatial)	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 (RWCU regenerative) channel head	Leakage boundary (spatial)	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 (RWCU regenerative) channel head	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	D C
Heat exchanger (RWCU regenerative) shell	Leakage boundary (spatial)	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 3.3.2-17: Reactor Water Cleanup 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 (RWCU regenerative) shell	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	D C
Orifice	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Orifice	Leakage boundary (spatial)	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	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	VII.E3.A-34	3.3-1, 002	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VII.E3.A-408	3.3-1, 126	A

Table 3.3.2-17: Reactor Water Cleanup 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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-09	3.2-1, 011	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	VII.E3.A-62	3.3-1, 002	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VII.E3.A-408	3.3-1, 126	A
Pump casing (Cleanup recirc)	Leakage boundary (spatial)	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)	Leakage boundary (spatial)	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 3.3.2-17: Reactor Water Cleanup 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 (Cleanup recirc)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Pump casing (Cleanup recirc)	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Pump casing (Cleanup recirc)	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Pump casing (Holding)	Leakage boundary (spatial)	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 (Holding)	Leakage boundary (spatial)	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 (Holding)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Pump casing (Holding)	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Pump casing (Holding)	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A

Table 3.3.2-17: Reactor Water Cleanup 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 (Precoat)	Leakage boundary (spatial)	Ductile 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 (Precoat)	Leakage boundary (spatial)	Ductile iron	Treated water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.E3.AP-31	3.3-1, 072	A
Pump casing (Precoat)	Leakage boundary (spatial)	Ductile iron	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Tank (Filter demineralizer) with internal coating	Leakage boundary (spatial)	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
Tank (Filter demineralizer) with internal coating	Leakage boundary (spatial)	Carbon steel	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
Tank (Filter demineralizer) with internal coating	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Tank (RWCU precoat) with internal coating	Leakage boundary (spatial)	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 3.3.2-17: Reactor Water Cleanup 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**
Tank (RWCU precoat) with internal coating	Leakage boundary (spatial)	Carbon steel	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
Tank (RWCU precoat) with internal coating	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A

Table 3.3.2-17: Reactor Water Cleanup 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 (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3-1, 244	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 3.3.2-18: Sampling 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 steel	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 steel	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	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger (H_2/O_2 analyzer panel) tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Heat exchanger (H_2/O_2 analyzer panel) tubes	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.F1.A-770a	3.3-1, 241	A
Heat exchanger (H_2/O_2 analyzer panel) tubes	Pressure boundary	Stainless steel	Closed-cycle cooling water (external)	Loss of material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-191	3.3-1, 047	A
Heat exchanger (Sample cooler) shell	Leakage boundary (spatial)	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 (Sample cooler) shell	Leakage boundary (spatial)	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
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 3.3.2-18: Sampling 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	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	Air – indoor uncontrolled (internal)	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 (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3-1, 006	A
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Orifice	Throttle	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3-1, 006	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3-1, 244	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Piping and 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

Table 3.3.2-18: Sampling 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 and 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 and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3-1, 006	A
Piping and piping components	Pressure boundary	Stainless steel	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Piping and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3-1, 244	B A
Piping and piping components	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A
Pump casing (H_2/O_2 analyzer)	Pressure boundary	Aluminum	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.A-451a	3.3-1, 189	A
Pump casing (H_2/O_2 analyzer)	Pressure boundary	Aluminum	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.H2.A-763a	3.3-1, 234	A
Pump casing (H_2/O_2 analyzer)	Pressure boundary	Aluminum	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.A-451a	3.3-1, 189	A
Pump casing (H_2/O_2 analyzer)	Pressure boundary	Aluminum	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.H2.A-763a	3.3-1, 234	A

Table 3.3.2-18: Sampling 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
Tank (Moisture separator)	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
Tank (Moisture separator)	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
Tank (Moisture separator)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3-1, 004	A
Tank (Moisture separator)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (internal)	Loss of material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3-1, 006	A
Valve body	Leakage boundary (spatial)	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 (spatial)	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 (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3-1, 244	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B 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

Table 3.3.2-18: Sampling 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 (internal)	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 (internal)	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	Gas (internal)	None	None	VII.J.AP-22	3.3-1, 120	A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3-1, 244	B A
Valve body	Pressure boundary	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 3.3.2-19: Plant Service Water 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 steel	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 steel	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 steel	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 steel	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 steel	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-241	3.3-1, 109	B
Bolting (Closure)	Mechanical closure	Carbon steel	Soil (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Bolting (Closure)	Mechanical closure	Galvanized steel	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	Galvanized steel	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	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	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	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	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	Air – outdoor (external)	Loss of material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3-1, 012	A

Table 3.3.2-19: Plant Service Water 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	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	Stainless steel	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	Stainless steel	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	Stainless steel	Soil (external)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3-1, 145	A
Bolting (Closure)	Mechanical closure	Stainless steel	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-243	3.3-1, 108	B
Bolting (Closure)	Mechanical closure	Stainless steel	Soil (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Hose	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
Hose	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
Hose	Pressure boundary	Stainless steel	Air – outdoor (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Hose	Pressure boundary	Stainless steel	Air – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3-1, 006	A
Hose	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
Hose	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
Hose	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-19: Plant Service Water 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	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	Air – outdoor (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Orifice	Pressure boundary	Stainless steel	Air – outdoor (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	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
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
Orifice	Throttle	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Leakage boundary (spatial)	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 3.3.2-19: Plant Service Water 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 and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-400b	3.3-1, 127	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 3.3.2-19: Plant Service Water 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 and piping components	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3-1, 134	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
Piping and 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 and 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 and piping components	Pressure boundary	Carbon steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.C1.AP-127	3.3-1, 097	A
Piping and 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

Table 3.3.2-19: Plant Service Water 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 and 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 and 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 and 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 and piping components	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and 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	B
Piping and 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	B
Piping and piping components	Pressure boundary	Gray cast iron	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 and piping components	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
Piping and piping components	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
Piping and piping components	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

Table 3.3.2-19: Plant Service Water 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 and piping components	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
Piping and piping components	Pressure boundary	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Low alloy 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 and piping components	Pressure boundary	Low alloy 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 and piping components	Pressure boundary	Low alloy 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 and piping components	Pressure boundary	Low alloy 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 and piping components	Pressure boundary	Low alloy steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and 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 and 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 and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping and piping components	Pressure boundary	Stainless steel	Air – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3-1, 006	A

Table 3.3.2-19: Plant Service Water 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 and 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 and 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 and piping components	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Piping and piping components	Pressure boundary	Stainless steel	Soil (external)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3-1, 144	B
Piping and piping components	Pressure boundary	Stainless steel	Soil (external)	Loss of material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-137	3.3-1, 107	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
Pump casing (PSW)	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 (PSW)	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 (PSW)	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 (PSW)	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 3.3.2-19: Plant Service Water 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 (PSW)	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 (PSW)	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing (PSW)	Pressure boundary	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
Pump casing (PSW)	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
Pump casing (PSW)	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Pump casing (Standby Diesel PSW)	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 (Standby Diesel PSW)	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 (Standby Diesel PSW)	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 (Standby Diesel PSW)	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 (Standby Diesel PSW)	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 (Standby Diesel PSW)	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-19: Plant Service Water 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 (Standby Diesel PSW)	Pressure boundary	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
Pump casing (Standby Diesel PSW)	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
Pump casing (Standby Diesel PSW)	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer (element)	Filter	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
Strainer (element)	Filter	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
Strainer (element)	Filter	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
Strainer (element)	Filter	Gray cast iron	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3-1, 072	A
Strainer (element)	Filter	Gray cast iron	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Strainer (element)	Filter	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
Strainer (element)	Filter	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
Strainer (element)	Filter	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

Table 3.3.2-19: Plant Service Water 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
Thermowell	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
Thermowell	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
Thermowell	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
Thermowell	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
Thermowell	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
Thermowell	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Thermowell	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
Thermowell	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
Thermowell	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
Thermowell	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

Table 3.3.2-19: Plant Service Water 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**
Thermowell	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Raw water (internal)	Flow blockage	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 (spatial)	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 (spatial)	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 (spatial)	Carbon steel	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 2
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 3.3.2-19: Plant Service Water 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	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
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
Valve body	Pressure boundary	Carbon steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
Valve body	Pressure boundary	Copper alloy with greater than 15% Zn	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% Zn	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% Zn	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% Zn	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% Zn	Raw water (internal)	Loss of material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3-1, 072	A

Table 3.3.2-19: Plant Service Water 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% Zn	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1
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	Air – outdoor (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 – outdoor (external)	Loss of material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3-1, 006	A
Valve body	Pressure boundary	Stainless steel	Lubricating oil (internal)	Loss of material	Lubricating Oil Analysis (B.2.3.25) One-Time Inspection (B.2.3.20)	VII.C1.AP-138	3.3-1, 100	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
Valve body	Pressure boundary	Stainless steel	Raw water (internal)	Wall thinning - erosion	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3-1, 126	E, 1

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage wall thinning due to erosion of components exposed to raw water within the scope of the GL 89-13 program.
2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage wall thinning due to erosion of components exposed to raw water not within the scope of the GL 89-13 program.

Table 3.3.2-20: Torus Water Cleanup 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 steel	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 steel	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	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	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	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3-1, 015	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A

Table 3.3.2-20: Torus Water Cleanup 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 and 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 and piping components	Pressure boundary	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Pump casing (Torus drainage and purification)	Leakage boundary (spatial)	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 (Torus drainage and purification)	Leakage boundary (spatial)	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 (Torus drainage and purification)	Leakage boundary (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3-1, 203	B A
Valve body	Leakage boundary (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3-1, 004	A

Table 3.3.2-20: Torus Water Cleanup 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 (spatial)	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 (spatial)	Stainless steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3-1, 021	B 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	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3-1, 203	B A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 3.3.2-21: Outside Structures HVAC 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 (HVAC Closure)	Mechanical closure	Carbon steel	Air – indoor uncontrolled (external)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F4.A-794	3.3-1, 260	A
Bolting (HVAC Closure)	Mechanical closure	Carbon steel	Air – indoor uncontrolled (external)	Loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F4.A-794	3.3-1, 260	A
Bolting (HVAC Closure)	Mechanical closure	Stainless steel	Air – outdoor (external)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F4.A-794	3.3-1, 260	A
Bolting (HVAC Closure)	Mechanical closure	Stainless steel	Air – outdoor (external)	Loss of material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F4.A-794	3.3-1, 260	A
Bolting (HVAC Closure)	Mechanical closure	Stainless steel	Air – outdoor (external)	Loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F4.A-794	3.3-1, 260	A
Ducting and ducting 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 ducting 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

Table 3.3.2-21: Outside Structures HVAC 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**
Ducting and ducting 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
Ducting and ducting 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.F2.A-722	3.3-1, 157	C
Fan 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
Fan housing	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
Fan housing	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
Fan housing	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.F2.A-722	3.3-1, 157	C

Table 3.3.2-21: Outside Structures HVAC 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**
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
Heater housing	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

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 aging management program 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 SYSTEM

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 the systems, which are addressed in this section are described in the indicated sections.

- Condensate and Feedwater System (Section 2.3.4.1)
- Main Steam System (Section 2.3.4.2)

3.4.2 Results

Table 3.4.2-1, Condensate and Feedwater System – Summary of Aging Management Evaluation

Table 3.4.2-2, Main Steam System – Summary of Aging Management Evaluation

3.4.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.4.2.1.1 Condensate and Feedwater System

Materials

The materials of construction for the FW system components are:

- Carbon steel
- Chromium molybdenum
- Stainless steel
- Titanium

Environments

The FW system components are exposed to the following environments:

- Air – indoor uncontrolled
- Raw water
- Treated water
- Treated water > 140°F

Aging Effects Requiring Management

The following aging effects associated with the FW system require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning - erosion
- Wall thinning - FAC

Aging Management Programs

The following AMPs manage the aging effects for the condensate and feedwater 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)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.4.2.1.2 Main Steam System

Materials

The materials of construction for the MS system components are:

- Carbon steel
- Stainless steel

Environments

The MS 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 MS system require aging management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning - erosion
- Wall thinning - FAC

Aging Management Programs

The following AMPs manage the aging effects for the MS 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)

3.4.2.2 Further Evaluation of Aging Management as Recommended by GALL-SLR

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the SLRA. For the Steam and Power Conversion 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 TLAAs, as defined in 10 CFR 54.3 (TN4878). The 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 Steam and Power Conversion Systems components, as described in SRP-SLR Item 3.4.2.2.1, is addressed as a TLAA in Section 4.3, Metal Fatigue.

3.4.2.2.2 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to SCC could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components, or (iv) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. The SCC in SS components is not an aging effect which requires management if: (i) plant-specific OE does not reveal a history of SCC and (ii) a one-time inspection demonstrates that no aging effect is occurring or apparent.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is occurring, the following AMPs describe acceptable programs to manage cracking due to SCC: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with those recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "Detection of Aging Effects" program element in AMP XI.M32.

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Ambient air at HNP is not subject to a marine atmosphere. The closest highway is US Highway 1 and the use of salt/ash to de-ice roadways is a rare occurrence in the south Georgia environments. A review of the over 30,000 CRs created during the last 10 years of operation 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 Steam and Power Conversion Systems are not susceptible to cracking due to SCC.

Plant-specific OE associated with insulated stainless steel components in the Steam and Power Conversion 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 HNP for insulated stainless steel components for these environments. This indicates 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 10 CFR Part 50, Appendix B CAP.

3.4.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel-alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components; or (iv) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel-alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other parts below the component. For outdoor insulated SS and nickel-alloy components, rain, and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel-alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect that requires management for SS and nickel-alloy components if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (ii) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur in the presence of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel-alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces

Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "Detection of Aging Effects" program element in AMP XI.M32.

The applicant may mitigate or prevent loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL- SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Ambient air at HNP is not subject to a marine atmosphere. The closest highway is US Highway 1 and the use of salt/ash to de-ice roadways is a rare occurrence in the south Georgia environments. A review of the over 30,000 CRs created during the last 10 years of operation 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 Steam and Power Conversion Systems are not susceptible to loss of material.

Plant-specific OE associated with insulated stainless steel and nickel alloy components in the Steam and Power Conversion 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 HNP for insulated stainless steel or nickel alloy components for these environments. This indicates 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 and nickel alloy components exposed to air and condensation, and, insulated stainless steel and nickel alloy components exposed to outdoor air and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix Section A.2, of this SRP-SLR).

Quality Assurance 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 Section A.4, "Operating Experience for Aging Management Programs."

The Operating Experience 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: (i) a 10 year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (ii) a 5 year search of plant-specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant-specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: (i) alternative examination methods (e.g., volumetric versus external visual), (ii) augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and (iii) additional trending parameters and decision points for implementing in more frequent inspections.

The applicant states: (i) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (ii) the basis for the adequacy of augmented or lack of augmented inspections, (iii)) the trend of which parameters will be followed as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (iv) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (v) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant-specific OE, two instances of a 360º 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the CLB intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in environments other than raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

HNP OE over the past 10 years indicates that recurring internal corrosion exists for steel components containing raw water from the Altamaha River; therefore, recurring internal corrosion is an applicable aging effect at HNP.

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is a new AMP and will address recurring internal corrosion by having measures in place to inspect additional samples for recurring degradation to ensure that corrective actions are appropriately addressing the associated causes. For ongoing degradation mechanisms (e.g., MIC and erosion) 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 will be conducted if one of the inspections does not meet acceptance criteria. The number of inspections will be increased in accordance with the CAP; however, no fewer than five additional inspections will be conducted for each inspection that does not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination are inspected, whichever is less.

Therefore, there is no need to augment the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP because it already includes specific measures to detect and manage recurring internal corrosion.

3.4.2.2.7 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

The SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation are provided for demonstrating that the specific material is not susceptible to SCC or the ambient environment is not aggressive in nature. Cracking due to SCC is an aging effect which requires management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC, then cracking is not an aging effect that requires management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, that determines whether the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper type, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper;*
- *5xxx series alloys with a magnesium content of 3.5 wt% or greater;*
- *6xxx series alloys in the F temper;*
- *7xxx series alloys in the F, T5x, or T6x temper;*
- *2xx.x and 7xx.x series alloys;*
- *3xx.x series alloys that contain copper; and*
- *5xx.x series alloys with a magnesium content of greater than 8 wt%.*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, 6063-T6, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, and product form. For tempers not addressed above, the basis used to determine that the alloy is not susceptible and technical information substantiating the basis is added to the SLRA.

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect which requires management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys include the presence of aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation layer or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the *components and locations exposed to the environment, description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.*

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. The GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Not applicable. There are no aluminum alloy components within the Steam and Power Conversion 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 highly alkaline environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the highly alkaline environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrate the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (i) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557;0 (ii) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (iii) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Not applicable. There are no components exposed to concrete susceptible to loss of material or SCC in the Steam and Power Conversion Systems.

3.4.2.2.9 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air greatly depend on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect which requires management for aluminum alloys if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (ii) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. Alternatively, loss of material due to pitting and crevice corrosion need not be managed if the type of aluminum is not susceptible to cracking and plant-specific operating experience does not reveal any issues related to loss of material due to pitting or crevice corrosion. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur in the presence of a source of moisture and halides. Alloy *susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.*

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of 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.

The applicant may mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL- SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Not applicable. There are no aluminum components within the Steam and Power Conversion Systems.

3.4.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Steam and Power Conversion System components:

- Section 4.3, *Metal Fatigue*

3.4.3 Conclusion

The Steam and Power Conversion 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 Steam and Power Conversion 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 the Steam and Power Conversion System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**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. Further evaluation is documented in Section 3.4.2.2.1.
3.4-1, 002	Stainless steel piping, piping components, exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection,"	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 stainless steel piping and piping components exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.4.2.2.2.
3.4-1, 003	Stainless steel, piping, piping components, exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection,"	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 stainless steel piping and piping components exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.4.2.2.3.
3.4-1, 004	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	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 005	Steel piping, piping components, exposed to steam, treated water	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. This line is also applied to heat exchanger components. The Flow-Accelerated Corrosion (B.2.3.9) AMP is used to manage wall thinning of steel piping, piping components, and heat exchanger components exposed to steam or treated water.
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 Steam and Power Conversion Systems.
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 steel and chrome-moly closure bolting exposed to air indoor uncontrolled.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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, and heat exchanger components exposed to steam or treated water >60°C (>140°F).
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. This line item is 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	**Components**	**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. 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 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. This line item is also applied to turbine hood 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 heat exchanger components and turbine hood components exposed to treated water. This line item is also applied to components in the ESF Systems.
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	Not applicable. There are no piping or piping components exposed to treated water or treated borated water in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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. 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. This line item is applied to components in the ESF Systems.
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 in the Steam and Power Conversion Systems.
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 Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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 Steam and Power Conversion 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 or piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Steam and Power Conversion 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 Steam and Power Conversion 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	Not applicable. There are no stainless steel heat exchanger components, piping, or piping components exposed to closed-cycle cooling water in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**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 Steam and Power Conversion 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 Steam and Power Conversion 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	Not applicable. There are no steel tanks exposed to soil, concrete, air, or condensation in the Steam and Power Conversion Systems.
3.4-1, 032	Gray cast iron, ductile iron piping, malleable iron 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, malleable iron, or ductile iron piping or piping components exposed to soil in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 033	Gray cast iron, ductile iron, malleable 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	Not applicable. There are no gray cast iron, ductile iron, malleable iron, or copper alloy >15% Zn piping and piping components exposed to treated water, raw water, or closed-cycle cooling water in the Steam and Power Conversion Systems.
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 or air outdoor. 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	Components	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 035	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum piping or piping components in the Steam and Power Conversion 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	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 ducting components exposed to air outdoor. This line item is 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	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 037	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel piping or piping components exposed to condensation in the Steam and Power Conversion Systems.
3.4-1, 038	Not applicable. This line item only applies to PWRs.				
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. 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. This line item is applied to components in the Auxiliary Systems.
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	Not applicable. There are no copper alloy piping or piping components exposed to lubricating oil in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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 and piping components exposed to lubricating oil. This line item is applied to components in the ESF Systems and Auxiliary Systems.
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 Steam and Power Conversion Systems.
3.4-1, 046	Not applicable. This line item only applies to PWRs.				
3.4-1, 047	Stainless steel piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no stainless steel piping, piping components, or closure bolting exposed to soil or concrete in the Steam and Power Conversion Systems.
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 Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 050	Steel piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no steel piping, piping components, or closure bolting exposed to soil or concrete in the Steam and Power Conversion Systems.
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 Steam and Power Conversion 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 Steam and Power Conversion 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 Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	Components	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	Not used. Aging effects for copper alloy components exposed to air are addressed by item 3.4-1, 106.
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	Not applicable. There are no glass piping elements exposed to lubricating oil, air, condensation, raw water, treated water, air with borated water leakage, gas, or closed-cycle cooling water in the Steam and Power Conversion Systems.
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 Steam and Power Conversion 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 Steam and Power Conversion 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 Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Not applicable. There are no steel piping or piping components exposed to air indoor controlled or gas in the Steam and Power Conversion Systems.
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. There are no metallic piping or piping components exposed to raw water or waste water that are susceptible to loss of material due to recurring internal corrosion in the Steam and Power Conversion Systems. Further evaluation is documented in Section 3.4.2.2.6.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 062	Steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no steel, stainless steel, or aluminum tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP exposed to treated water in the Steam and Power Conversion Systems.
3.4-1, 063	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no insulated steel or copper alloy (>15% Zn) piping, piping components, or tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP exposed to air or condensation in the Steam and Power Conversion Systems.
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 thermal insulation are addressed by line 3.3-1, 182.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 066	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, lubricating oil	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. There are no piping, piping components, heat exchangers, or tanks with internal coating/linings exposed to closed-cycle cooling water, raw water, treated water, or lubricating oil in the Steam and Power Conversion Systems.
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	Not applicable. There are no piping, piping components, or heat exchangers with internal coating/linings exposed to closed-cycle cooling water, raw water, treated water, or lubricating oil in the Steam and Power Conversion Systems.
3.4-1, 068	Gray cast iron, ductile iron, malleable iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. There are no gray cast iron, ductile iron, or malleable iron piping or piping components with internal coatings in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**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	Not applicable. There is no stainless steel, steel, nickel alloy, or copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, or waste water in the Steam and Power Conversion Systems.
3.4-1, 072	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/ bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no stainless steel, steel, or aluminum piping or piping components exposed to soil or concrete in the Steam and Power Conversion Systems.
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	Not applicable. There is no stainless steel closure bolting exposed to air, soil, concrete, underground, or waste water in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 074	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. There are no stainless steel underground components in the Steam and Power Conversion Systems. Further evaluation is documented in Section 3.4.2.2.2.
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 Steam and Power Conversion Systems.
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	Not applicable. There are no elastomer components exposed to air or condensation in the Steam and Power Conversion Systems.
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 in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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	Not applicable. Based on a review of HNP OE, there are no instances of long-term loss of material in the Steam and Power Conversion Systems.
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 Steam and Power Conversion 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	Not applicable There are no stainless steel or nickel alloy tanks exposed to treated water in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**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 components and heat exchanger 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 and piping 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 in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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 steel, stainless steel, or copper alloy piping and piping components not covered by NRC GL 89-13 exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 090	Steel, stainless steel, copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel, stainless steel, or copper alloy heat exchanger tubes not covered by NRC GL 89-13 exposed to raw water in the Steam and Power Conversion Systems.
3.4-1, 091	Steel, stainless steel, copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel, stainless steel, or copper alloy heat exchanger tubes not covered by NRC GL 89-13 exposed to raw water in the Steam and Power Conversion 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 Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Components	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 094	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum underground piping or piping components in the Steam and Power Conversion Systems. Further evaluation is documented in Section 3.4.2.2.9.
3.4-1, 095	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Not applicable. There are no stainless steel or nickel alloy underground piping or piping components in the Steam and Power Conversion Systems. Further evaluation is documented 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 in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Components	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 097	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Steam and Power Conversion Systems. Further evaluation is documented 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 in the Steam and Power Conversion Systems. Further evaluation is documented in Section 3.4.2.2.3.
3.4-1, 099	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no stainless steel tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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 in the Steam and Power Conversion Systems. 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 in the Steam and Power Conversion Systems.
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 in the Steam and Power Conversion Systems. 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	**Components**	**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)	Not applicable. There are no insulated stainless steel or nickel alloy piping, piping components, or tanks exposed to air or condensation in the Steam and Power Conversion Systems. Further evaluation is documented 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	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 104	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. There are no insulated stainless steel piping or piping components exposed to air or condensation in the Steam and Power Conversion Systems. 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	**Components**	**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 Steam and Power Conversion 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. 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 air indoor uncontrolled or air outdoor. This line item is 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	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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 Steam and Power Conversion Systems.
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, piping components, or tanks in the Steam and Power Conversion Systems. 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	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 112	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum underground piping, piping components, or tanks in the Steam and Power Conversion Systems. Further evaluation is documented in Section 3.4.2.2.7.
3.4-1, 114	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not used. Cracking of titanium heat exchanger tubes exposed to raw water with the heat transfer function is addressed by item 3.3-1, 236.
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 ASTM Grades 1, 2, 7, 9, 11, or 12 titanium components exposed to treated water in the Steam and Power Conversion Systems.
3.4-1, 116	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium heat exchanger tubes exposed to closed-cycle cooling water in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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 Steam and Power Conversion 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 Steam and Power Conversion 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	Components	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 Steam and Power Conversion 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	Not applicable. There are no elastomer piping, piping components, or seals exposed to air in the Steam and Power Conversion Systems.
3.4-1, 123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer piping, piping components, or seals exposed to air in the Steam and Power Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 124	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no PVC components in the Steam and Power Conversion Systems.
3.4-1, 125	PVC, CFRP piping, piping components, tanks exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks" or AMP XI.M43, “High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping”	No	Not applicable. There are no PVC or CFRP components in the Steam and Power Conversion 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 exposed to closed-cycle cooling water in the Steam and Power Conversion 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 Steam and Power Conversion Systems.
3.4-1, 128	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no copper alloy components exposed to concrete in the Power and Steam Conversion Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Components**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 129	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no copper alloy components exposed to soil or underground in the Steam and Power Conversion 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.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 titanium heat exchanger tubesheets exposed to raw water.
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.				
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 Steam and Power Conversion Systems.
3.4-1, 134	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	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 titanium heat exchanger tubes exposed to raw water.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Components	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 135	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	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 Steam and Power Conversion Systems.

Table 3.4.2-1: Condensate and Feedwater 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 steel	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 steel	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	Chromium molybdenum steel	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	Chromium molybdenum steel	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4-1, 006	A
Heat exchanger (Main condenser) shell	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 (Main condenser) shell	Holdup and plateout	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4-1, 015	B A
Heat exchanger (Main condenser) shell	Holdup and plateout	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	C
Heat exchanger (Main condenser) shell	Holdup and plateout	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4-1, 005	C
Heat exchanger (Main condenser) tubes	Holdup and plateout	Titanium	Raw water (internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-482	3.4-1, 134	A

Table 3.4.2-1: Condensate and Feedwater 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 (Main condenser) tubes	Holdup and plateout	Titanium	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Main condenser) tubes	Holdup and plateout	Titanium	Treated water (external)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.C1.A-765	3.3-1, 236	B A
Heat exchanger (Main condenser) tubes	Holdup and plateout	Titanium	Treated water (external)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	C
Heat exchanger (Main condenser) tubesheet	Holdup and plateout	Titanium	Raw water (internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.D2.S-478b	3.4-1, 130	A
Heat exchanger (Main condenser) tubesheet	Holdup and plateout	Titanium	Raw water (internal)	Wall thinning - erosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3-1, 126	E, 1
Heat exchanger (Main condenser) tubesheet	Holdup and plateout	Titanium	Treated water (external)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.C1.A-765	3.3-1, 236	B A
Heat exchanger (Main condenser) tubesheet	Holdup and plateout	Titanium	Treated water (external)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	C

Table 3.4.2-1: Condensate and Feedwater 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
Low pressure 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
Low pressure turbine hood	Holdup and plateout	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4-1, 015	D C
Low pressure turbine hood	Holdup and plateout	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	C
Low pressure turbine hood	Holdup and plateout	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4-1, 005	C
Piping and piping components	Leakage boundary (spatial)	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 and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	VIII.D2.S-11	3.4-1, 001	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D2.SP-73	3.4-1, 014	B A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	A
Piping and piping components	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4-1, 005	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VIII.D2.SP-118a	3.4-1, 002	A

Table 3.4.2-1: Condensate and Feedwater 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 and piping components	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VIII.D2.SP-127a	3.4-1, 003	A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4-1, 011	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D2.SP-87	3.4-1, 085	B A
Piping and piping components	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	A
Thermowell	Leakage boundary (spatial)	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
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D2.SP-73	3.4-1, 014	B A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	A
Thermowell	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4-1, 005	A

Table 3.4.2-1: Condensate and Feedwater 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 (spatial)	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 (spatial)	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D2.SP-73	3.4-1, 014	B A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	A
Valve body	Leakage boundary (spatial)	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4-1, 005	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Cracking	One-Time Inspection (B.2.3.20)	VIII.D2.SP-118a	3.4-1, 002	A
Valve body	Leakage boundary (spatial)	Stainless steel	Air – indoor uncontrolled (external)	Loss of material	One-Time Inspection (B.2.3.20)	VIII.D2.SP-127a	3.4-1, 003	A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4-1, 011	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D2.SP-87	3.4-1, 085	B A
Valve body	Leakage boundary (spatial)	Stainless steel	Treated water > 140°F (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	A

Table 3.4.2-1: Condensate and Feedwater 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	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)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.D2.SP-73	3.4-1, 014	B A
Valve body	Pressure boundary	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4-1, 060	A
Valve body	Pressure boundary	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4-1, 005	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 used to manage wall thinning due to erosion of components exposed to raw water not within the scope of the GL 89-13 program.

Table 3.4.2-2: Main Steam 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 steel	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 steel	Air – indoor uncontrolled (external)	Loss of preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4-1, 006	A
Heat exchanger (Offgas pre-heater) channel head	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 (Offgas pre-heater) channel head	Holdup and plateout	Carbon steel	Steam (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-160	3.4-1, 014	D C
Heat exchanger (Offgas pre-heater) channel head	Holdup and plateout	Carbon steel	Steam (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	C
Heat exchanger (Offgas pre-heater) channel head	Holdup and plateout	Carbon steel	Steam (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-15	3.4-1, 005	C
Heat exchanger (Offgas pre-heater) shell	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 (Offgas pre-heater) shell	Holdup and plateout	Carbon steel	Steam (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-160	3.4-1, 014	D C

Table 3.4.2-2: Main Steam 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 (Offgas pre-heater) shell	Holdup and plateout	Carbon steel	Steam (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	C
Heat exchanger (Offgas pre-heater) shell	Holdup and plateout	Carbon steel	Steam (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-15	3.4-1, 005	C
Heat exchanger (Offgas pre-heater) tubes	Holdup and plateout	Stainless steel	Steam (external)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4-1, 011	D C
Heat exchanger (Offgas pre-heater) tubes	Holdup and plateout	Stainless steel	Steam (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4-1, 084	B A
Heat exchanger (Offgas pre-heater) tubes	Holdup and plateout	Stainless steel	Steam (external)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	C
Heat exchanger (Offgas pre-heater) tubes	Holdup and plateout	Stainless steel	Steam (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4-1, 011	D C
Heat exchanger (Offgas pre-heater) tubes	Holdup and plateout	Stainless steel	Steam (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4-1, 084	B A
Heat exchanger (Offgas pre-heater) tubes	Holdup and plateout	Stainless steel	Steam (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	C

Table 3.4.2-2: Main Steam 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 (Offgas pre-heater) tubesheet	Holdup and plateout	Stainless steel	Steam (external)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4-1, 011	D C
Heat exchanger (Offgas pre-heater) tubesheet	Holdup and plateout	Stainless steel	Steam (external)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4-1, 084	B A
Heat exchanger (Offgas pre-heater) tubesheet	Holdup and plateout	Stainless steel	Steam (external)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	C
Heat exchanger (Offgas pre-heater) tubesheet	Holdup and plateout	Stainless steel	Steam (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4-1, 011	D C
Heat exchanger (Offgas pre-heater) tubesheet	Holdup and plateout	Stainless steel	Steam (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4-1, 084	B A
Heat exchanger (Offgas pre-heater) tubesheet	Holdup and plateout	Stainless steel	Steam (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	C
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

Table 3.4.2-2: Main Steam 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	Holdup and plateout	Stainless steel	Steam (internal)	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4-1, 011	B A
Orifice	Holdup and plateout	Stainless steel	Steam (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4-1, 084	B A
Orifice	Holdup and plateout	Stainless steel	Steam (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	A
Piping and 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 and piping components	Holdup and plateout	Carbon steel	Steam (internal)	Cumulative fatigue damage	TLAA - Section 4.3, Metal Fatigue	VIII.B2.S-08	3.4-1, 001	A
Piping and piping components	Holdup and plateout	Carbon steel	Steam (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-160	3.4-1, 014	B A
Piping and piping components	Holdup and plateout	Carbon steel	Steam (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	A
Piping and piping components	Holdup and plateout	Carbon steel	Steam (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-15	3.4-1, 005	A
Piping and piping components	Holdup and plateout	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4-1, 014	B A

Table 3.4.2-2: Main Steam 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 and piping components	Holdup and plateout	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D1.S-408	3.4-1, 060	A
Piping and piping components	Holdup and plateout	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.E.S-16	3.4-1, 005	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	Steam (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-160	3.4-1, 014	B A
Valve body	Holdup and plateout	Carbon steel	Steam (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4-1, 060	A
Valve body	Holdup and plateout	Carbon steel	Steam (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-15	3.4-1, 005	A
Valve body	Holdup and plateout	Carbon steel	Treated water (internal)	Loss of material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4-1, 014	B A
Valve body	Holdup and plateout	Carbon steel	Treated water (internal)	Wall thinning - erosion	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D1.S-408	3.4-1, 060	A
Valve body	Holdup and plateout	Carbon steel	Treated water (internal)	Wall thinning - FAC	Flow-Accelerated Corrosion (B.2.3.9)	VIII.E.S-16	3.4-1, 005	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 systems, or portions of the systems, which are addressed in this section are described in the indicated sections.

- Primary Containment (Section 2.4.1)
- Component Supports and Structural Commodity Group (Section 2.4.2)
- Concrete Commodity Group (Section 2.4.3)
- Control Building (Section 2.4.4)
- Canes, Heavy Loads, Rigging (Section 2.4.5)
- Emergency Diesel Generator Building (Section 2.4.6)
- Fire Barrier Commodity Group (Section 2.4.7)
- Intake Structure (Section 2.4.8)
- Main Stack (Section 2.4.9)
- Radwaste Buildings (Section 2.4.10)
- Reactor Buildings (Section 2.4.11)
- Switchyard Structures (Section 2.4.12)
- Turbine Buildings (Section 2.4.13)
- Yard Structures and Tank Foundations (Section 2.4.14)

3.5.2 Results

Table 3.5.2-1, Primary Containment – Summary of Aging Management Evaluation

Table 3.5.2-2, Component Supports and Structural Commodity Group – Summary of Aging Management Evaluation

Table 3.5.2-3, Concrete Commodity Group – Summary of Aging Management Evaluation

Table 3.5.2-4, Control Building – Summary of Aging Management Evaluation

Table 3.5.2-5, Canes, Heavy Loads, Rigging – Summary of Aging Management Evaluation

Table 3.5.2-6, Emergency Diesel Generator Building – Summary of Aging Management Evaluation

Table 3.5.2-7, Fire Barrier Commodity Group – Summary of Aging Management Evaluation

Table 3.5.2-8, Intake Structure – Summary of Aging Management Evaluation

Table 3.5.2-9, Main Stack – Summary of Aging Management Evaluation

Table 3.5.2-10, Radwaste Buildings – Summary of Aging Management Evaluation

Table 3.5.2-11, Reactor Buildings – Summary of Aging Management Evaluation

Table 3.5.2-12, Switchyard Structures – Summary of Aging Management Evaluation

Table 3.5.2-13, Turbine Buildings – Summary of Aging Management Evaluation

Table 3.5.2-14, Yard Structures and Tank Foundations – 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 primary containment components are:

- Coatings
- Concrete (reinforced)
- Concrete (unreinforced)
- Dissimilar metal welds
- Elastomer, rubber and other similar materials
- Lubrite®
- Stainless steel
- Stainless steel dissimilar metal welds
- Steel

Environments

The primary containment structure components are exposed to the following environments:

- Air – indoor uncontrolled
- Concrete
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the primary containment structure 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 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)

3.5.2.1.2 Component Supports and Structural Commodity Group

Materials

The materials of construction for the component supports and structural commodity group are:

- Aluminum
- Asbestos
- Calcium silicate
- Ceramic
- Elastomer
- Fiberglass
- Grout
- Kaowool
- Stainless steel
- Steel

Environments

The component supports and structural commodity group are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater/soil
- Treated water

Aging Effects Requiring Management

The following component supports and structural commodity group aging effects require management:

- Cracking
- Loss of fracture toughness
- Loss of intended function
- Loss of material
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduced thermal insulation resistance

- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Component Supports and Structural Commodity Group 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)

3.5.2.1.3 Concrete Commodity Group

Materials

The materials of construction for the concrete commodity group component types are:

- Concrete (reinforced)
- Concrete block
- Concrete; grout

Environments

The concrete commodity group components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater/soil
- Water - flowing

Aging Effects Requiring Management

The following concrete commodity group aging effects require management:

- Cracking
- Distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of strength
- Reduction in concrete anchor capacity

Aging Management Programs

The following AMPs manage the aging effects for the Concrete Commodity Group 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)

3.5.2.1.4 Control Building

Materials

The materials of construction for the control building component types are:

- Aluminum
- Steel

Environments

The control building component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following control building aging effects require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Control Building components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.5 Cranes, Heavy Loads, Rigging

Materials

The materials of construction for cranes, heavy loads, rigging component types are:

- Steel

Environments

The cranes, heavy loads, rigging component are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effects Requiring Management

The following cranes, heavy loads, rigging aging effects 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 components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)
- Structures Monitoring (B.2.3.33)

3.5.2.1.6 Emergency Diesel Generator Building

Materials

The materials of construction for the EDG building component types are:

- Steel

Environments

The EDG building component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following EDG building aging effects require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Emergency Diesel Generator Building components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.7 Fire Barrier Commodity Group

Materials

The materials of construction for the fire barrier commodity group components types are:

- Aluminum
- Cementitious
- Concrete (reinforced)
- Concrete block
- Copper alloy
- Elastomer
- Gypsum
- Polystyrene foam

- Rockwool
- Silicate
- Stainless steel
- Steel
- Subliming
- Urethane foam

Environments

The fire barrier commodity group are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following fire barrier commodity group aging effects require management:

- Change in material properties
- Cracking
- Delamination
- Hardening
- Loss of material
- Loss of strength
- Separation
- Shrinkage

Aging Management Programs

The following AMPs manage the aging effects for the Fire Barrier Commodity Group components:

- Fire Protection (B.2.3.15)
- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.8 Intake Structure

Materials

The materials of construction for the intake structure component types are:

- Steel

Environments

The intake structure components are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Water- flowing or standing

Aging Effects Requiring Management

The following intake structure aging effects require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Intake Structure components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)
- Structures Monitoring (B.2.3.33)

3.5.2.1.9 Main Stack

Materials

The materials of construction for the main stack component types are:

- Steel

Environments

The Main Stack component are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater/soil

Aging Effects Requiring Management

The following Main Stack aging effects require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Main Stack components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.10 Radwaste Building

Materials

The materials of construction for the radwaste building component types are:

- Steel

Environments

The radwaste building component are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following radwaste building aging effects require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Radwaste Building components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.11 Reactor Building

Materials

The materials of construction for the reactor building component types are:

- Aluminum
- Boral
- Polymeric
- Rubber
- Stainless steel
- Steel

Environments

The reactor building component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Treated water

Aging Effects Requiring Management

The following reactor building aging effects require management:

- Blistering
- Change in dimensions
- Cracking
- Hardening
- 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 components:

- Monitoring of Neutron-Absorbing Material 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)

3.5.2.1.12 Switchyard Structures

Materials

The materials of construction for the switchyard structures component types are:

- Steel

Environments

The switchyard structures component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following switchyard structures aging effects require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Switchyard Structures components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.13 Turbine Building

Materials

The materials of construction for the turbine building component types are:

- Aluminum
- Polymeric
- Steel

Environments

The turbine building component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following turbine building aging effects require management:

- Blistering
- Cracking
- Hardening
- Loss of material
- Loss of preload
- Loss of strength

Aging Management Programs

The following AMPs manage the aging effects for the Turbine Building components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.14 Yard Structures and Tank Foundations

Materials

The materials of construction for the yard structures and tank foundations component types are:

- Aluminum
- Steel

Environments

The yard structures and tank foundations are exposed to the following environments:

- Air – outdoor
- Groundwater/soil

Aging Effects Requiring Management

The following yard structures and tank foundations aging effects require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following AMPs manage the aging effects for the Yard Structures and Tank Foundations components:

- Structures Monitoring (B.2.3.33)

3.5.2.2 Further Evaluation of Aging Management as Recommended by GALL-SLR

The basic acceptance criteria defined in Section 3.5.2.1 need to be applied first for all of the AMRs and AMPs 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 Recommended," then additional criteria apply for each of the following aging effect/aging mechanism combinations. Refer to Table 3.5-1, comparing the "Further Evaluation Recommended" column and the "GALL-SLR Item" column, for the AMR items that reference the following subsections.

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Containment, Structures and Component Supports, those programs are addressed in the following subsections. Italicized text is taken directly from NUREG-2192.

3.5.2.2.1 PWR and BWR Containments

3.5.2.2.1.1 Cracking And Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, and Cracking Due to Differential Settlement and Erosion of Porous Concrete Subfoundations

Cracking and distortion due to increased stress levels from settlement could occur in PWR and BWR concrete and steel containments. The existing program relies on ASME Code Section XI, Subsection IWL to manage these aging effects. Also, reduction of foundation strength and cracking, due to differential settlement and erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. The existing program relies on the structures monitoring program to manage these aging effects. However, some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system to control settlement, further evaluation is recommended to verify the continued functionality of the dewatering system during the subsequent period of extended operation.

As summarized in item numbers 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 subfoundations are not applicable to the HNP 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 foundation. As such, the primary containment structure internal concrete is not exposed to groundwater/soil environment and cannot settle independently of the foundation. As reiterated below, HNP buildings do not have porous subfoundations and a de-watering system is not relied on.

3.5.2.2.1.2 Reduction of Strength and Modulus Due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR concrete and steel containments. The implementation of 10 CFR 50.55a (TN249) and ASME Code Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated *temperature. Subsection CC-3440 of ASME Code Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects for portions of the concrete containment components that exceed specified temperature limits (i.e., general area temperature greater than 66 °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. Acceptance criteria are described in BTP RLSB-1, "Aging Management Review – Generic, July 2017" (Appendix Section A.1 of this SRP-SLR).*

As summarized in item number 3.5-1, 003, reduction of strength and modulus of concrete due to elevated temperatures is not applicable to the HNP Mark I steel containment. The bulk drywell temperature is maintained by the primary containment cooling system. Concrete structural components located inside the drywell are not subject to general area temperatures greater than 150ºF.

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 (TN249), Appendix J AMPs, to manage this aging effect. Further evaluation of plant-specific programs is recommended to manage this aging effect if corrosion is indicated from the IWE examinations. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

As summarized in item numbers 3.5-1, 004, and 3.5-1, 035, the ASME Section XI, Subsection IWE AMP (B.2.3.29) and 10 CFR Part 50, Appendix J AMP (B.2.3.31) is used to manage the loss of material of dissimilar metal welds, stainless steel, and steel elements of containment exposed to air – indoor uncontrolled and concrete environments, with the results of inspections of accessible areas as leading indicators of the potential loss of material in inaccessible areas. Item number 3.5-1, 004 is for BWR Mark III containments, but HNP finds this item number applicable for the aging effect and environment combination.

The item number 3.5-1, 005 is not applicable to the HNP Mark I steel containment.

OE with inspection of the accessible areas of the containment liner and moisture barrier is summarized in the ASME Section XI, Subsection IWE AMP (B.2.3.29). In addition, the 10 CFR Part 50, Appendix J AMP (B.2.3.31) works in conjunction with ASME Section XI, Subsection IWE AMP (B.2.3.29) to have visual inspections of the containment performed prior to each Type A testing. A review of plant OE and IWE inspection reports has not identified instances of liner corrosion beyond minor surface corrosion that was evaluated and corrected.

2. *Loss of material due to general, pitting, and crevice corrosion could occur in steel torus shell of Mark I containments. The existing program relies on ASME*

Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J, to manage this aging effect. If corrosion is significant, recoating of the torus is recommended. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

As summarized in item number 3.5-1, 006, the ASME Section XI, Subsection IWE AMP (B.2.3.29) and the 10 CFR Part 50, Appendix J AMP (B.2.3.31) is used to manage the loss of material of steel elements in the torus shell exposed to air – indoor uncontrolled and treated water environments. The accessible portions of the torus shell are required to be 100% visually examined in the current ISI interval.

Examinations conducted in accordance with ASME Section XI, Subsection IWE have not identified significant corrosion in the steel torus shell of the HNP 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 of plant-specific programs is recommended to manage this aging effect if corrosion is significant. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

As summarized in item number 3.5-1, 007, the ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage the loss of material of steel torus shell, ring girders, and jet deflectors exposed to air – indoor uncontrolled and treated water environments during the SPEO.

The Structures Monitoring AMP (B.2.3.33) is used to manage loss of material of structural steel associated with the torus internal catwalk support columns exposed to a treated water environment.

Steel torus ring girders of the HNP 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 jet deflectors that has identified significant loss of material as a result of exposure to air – indoor and treated water.

3.5.2.2.1.4 Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature

Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete containments is a TLAA as defined in 10 CFR 54.3 (TN4878). The TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed separately in Section 4.5, "Concrete Containment Tendon Prestress Analysis," and/or Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-LR.

As summarized in item number 3.5-1, 008, loss of prestress due to relaxation, shrinkage, creep, and elevated temperature is not applicable to the HNP 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, 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. The 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 appropriate10 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 number 3.5-1, 009, cumulative fatigue damage is identified as a TLAA. Components with an existing CLB fatigue analysis include the downcomers, torus shell, vent header, vent lines, and vent line bellows, and the refueling water seal assembly (including reactor bellows support skirt and reactor well seal bulkhead plate).

The components with an existing CLB fatigue waiver include the containment penetrations and the drywell penetration bellows.

As such, as summarized in item number 3.5-1, 027 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 Section XI, Subsection IWE AMP (B.2.3.29), including an enhancement to inspect accessible portions for cracking, and the 10 CFR Part 50, Appendix J AMP (B.2.3.31), respectively, during the SPEO.

Item number 3.5-1, 040 is not applicable to the HNP Mark I steel containment. This item number is applicable only to BWR Mark II containments.

3.5.2.2.1.6 Cracking due to Stress Corrosion Cracking

The SCC of SS penetration sleeves, penetration bellows, vent line bellows, suppression chamber shell (interior surface), and dissimilar metal welds could occur in PWR and/or BWR containments. The existing program relies on ASME Code Section XI, Subsection IWE and 10 CFR Part 50 (TN249), Appendix J, to manage this aging effect. Further evaluation, including consideration of SCC susceptibility and applicable OE related to detection and additional appropriate examinations/evaluations implemented to detect this aging effect for these SS components and dissimilar metal welds is recommended.

As summarized in item numbers 3.5-1, 010 and 3.5-1, 039, cracking due to stress corrosion cracking (SCC) is an applicable aging effect in stainless steel or nickel alloy components. Stainless steel or nickel alloy components of the primary containment include: penetration assemblies - mechanical (bellows) and electrical (item number 3.5-1, 010), vent line bellows (item numbers 3.5-1, 010 and 3.5-1, 039), and the refueling water seal assembly (including reactor bellows support skirt, reactor well seal bulkhead plate) (item number 3.5-1, 039). Connection of these stainless steel or nickel alloy components to steel piping or the steel containment involve dissimilar metal welds (DMWs). HNP 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 reactor shield wall (also referred to as the sacrificial shield wall) 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 or Inconel (nickel alloy).

Item number 3.5-1, 038 is not applicable to the HNP Mark I steel containment. This item number is applicable only to BWR Mark III containments.

The following primary containment penetrations, equipped with stainless steel or nickel alloy bellows, are subject to elevated temperatures during normal operation:

Table 3.5.2.2.1.6-1: Primary Containment Penetrations Subject to Elevated Temperatures During Normal Operation

Penetration Number	Description	Piping Material
7A	Main Steam Line A	carbon steel
7B	Main Steam Line B	carbon steel

Table 3.5.2.2.1.6-1: Primary Containment Penetrations Subject to Elevated Temperatures During Normal Operation

Penetration Number	Description	Piping Material
7C	Main Steam Line C	carbon steel
7D	Main Steam Line D	carbon steel
8	Condensate Drain	carbon steel
9A	Primary Feedwater Line A	carbon steel
9B	Primary Feedwater Line B	carbon steel
10	Steam to RCIC Turbine	carbon steel
11	Steam to HPCI Turbine	carbon steel
12	RHR Shutdown Cooling Suction	carbon steel
13A	RHR Return to Recirc Loop	carbon steel
13B	RHR Return to Recirc Loop	carbon steel
14	RWC Supply	stainless steel
212	RCIC Turbine Exhaust	carbon steel
214	HPCI Turbine Exhaust	carbon steel

The torus and drywell shells at HNP, as well as penetration nozzles, sleeves, etc., are made of carbon steel and not susceptible to SCC.

Cracking due to SCC of stainless steel or nickel alloy penetration bellows (hot fluid penetrations), and associated DMWs will be managed by the ASME Section XI, Subsection IWE AMP (B.2.3.29) and the 10 CFR Part 50, Appendix J AMP (B.2.3.31), as clarified below. The ASME Section XI, Subsection IWE AMP (B.2.3.29) will be enhanced to include one-time volumetric/surface examination of 20% of these 24 penetration bellows prior to SPEO (i.e., 5 inspections per Unit).

Cracking due to SCC for the refueling water seal assembly will be managed by the Structures Monitoring AMP (B.2.3.33) instead of ASME Section XI, Subsection IWE AMP (B.2.3.29); as it is not a pressure retaining component.

3.5.2.2.1.7 Loss of Material (Scaling, Spalling) and Cracking due to Freeze-Thaw

Loss of material (scaling, spalling) and cracking due to freeze-thaw could occur in inaccessible areas of PWR and BWR concrete containments. Further evaluation is recommended of this aging effect to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL, and/or

Structures Monitoring AMPs, to manage these aging effects for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

As summarized in item number 3.5-1, 011, loss of material (scaling, spalling) and cracking due to freeze-thaw is not applicable to the HNP 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 structure internal concrete is not exposed to air – outdoor, or groundwater/soil environments.

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 number 3.5-1, 012, cracking due to expansion from reaction with aggregates is not applicable to the HNP Mark I steel containment. The primary containment structure is completely enclosed and sheltered within 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 3.5.2.2.2.1.2 and item number 3.5-1, 043.

3.5.2.2.1.9 Increase in Porosity and Permeability due to Leaching of Calcium Hydroxide and Carbonation

Increase in porosity and permeability due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. Further evaluation is recommended if leaching is observed in accessible areas that impact intended functions, to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

As summarized in item number 3.5-1, 014, increase in porosity and permeability due to leaching of calcium hydroxide and carbonation is not applicable to the HNP 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 structure internal concrete elements are not exposed to air – outdoor or groundwater/soil environments where leaching and carbonation could occur.

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

3.5.2.2.2.1 Aging Management of Inaccessible Areas

1. *Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures. Further evaluation of inaccessible areas of these groups of structures for plants located in moderate to severe weathering conditions is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

As summarized in item number 3.5-1, 042, loss of material (spalling, scaling) and cracking due to freeze-thaw is applicable to HNP reinforced concrete structures exposed to an air – outdoor or groundwater/soil environments. Non-containment structures at HNP consists of Groups 1, 2, 3, 8, and 9. There are no concrete Groups 5 and 7 components applicable to HNP. At HNP, structures are located in a region where weathering conditions are considered moderate, as shown in ASTM C33-90, Figure 1. The concrete met all the standard code requirements. Air entrainment content conformed to the design requirements of ACI 211.1 as determined by ASTM C231.

OE has not identified any significant loss of material (spalling, scaling) and cracking due to freeze-thaw of reinforced concrete structures within the scope of license renewal. The Structures Monitoring AMP (B.2.3.33) includes inspection of concrete in the accessible areas. 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. Additionally, the Structures Monitoring AMP (B.2.3.33) performs opportunistic inspections to confirm the absence of aging effects by examining normally inaccessible structural components, when exposed because of excavation or modification, 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 of inaccessible areas of these groups of structures is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

As summarized in item number 3.5-1, 043 cracking due to expansion and reaction with aggregates, is considered applicable to HNP reinforced concrete structures exposed to air – indoor uncontrolled, air – outdoor, and groundwater/soil environments. The concrete work performed for the Groups 1-4, 8, and 9 structures at HNP was in accordance with ACI 318-63, Building Code Requirements for Reinforced Concrete, and ACI 301-66, Specifications for Structural Concrete for Buildings. Concrete aggregates conform to the requirements of ASTM C33, Standard Specification of Concrete Aggregates. There are no concrete Groups 5 and 7 components applicable to HNP. Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, organic matter, and other deleterious substances. Tests and petrographic examinations of the concrete were performed according to ASTM C289-64 and ASTM C295.

OE has not identified any evidence of reaction with aggregates at HNP. Nevertheless, the Structures Monitoring AMP (B.2.3.33) continues to inspect and monitor concrete structures for cracking, including hairline and patterned cracking, which are typical evidence of reaction with aggregates, such as alkali-silicate reaction (ASR). 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. Opportunistic inspections will be performed to confirm the absence of aging effects by examining normally inaccessible structural components, when exposed because of excavation or modification. If cracking due to expansion and reaction with aggregates were significant, pattern cracking would be expected over the accessible surfaces. This has not occurred. This provides objective evidence that cracking associated with expansion due to reaction with aggregates has not yet occurred. Considering the age of HNP, the possibility of occurrence becomes unlikely. Nevertheless, HNP will continue to look for indications of cracking associated with expansion due to reaction with aggregates. 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 Structures Monitoring AMP (B.2.3.33).

Since cracking due to expansion and reaction with aggregates occurs at a comparatively slow rate, the required five-year inspection frequency, of the Structures Monitoring AMP (B.2.3.33), is adequate to address any significant concrete damage due to cracking due to expansion and reaction with aggregates before a loss of intended function. As a result, the Structures Monitoring AMP (B.2.3.33) is expected to adequately manage the cracking due to expansion and reaction with aggregates that could occur in inaccessible reinforced concrete areas of Groups 1-4, 8, and 9 structures.

3. *Cracking and distortion due to increased stress levels from settlement could occur in below-grade inaccessible concrete areas of structures for all groups, and reduction in foundation strength, and cracking due to differential settlement and erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1–3, 5–9 structures. The existing program relies on structure monitoring programs to manage these aging effects. Some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system, verification is recommended of the continued functionality of the dewatering system during the subsequent period of extended operation. No further evaluation is recommended if this activity is included in the scope of the applicant's structures monitoring program.*

As summarized in item number 3.5-1, 044, HNP does not rely on a dewatering system. However, inspections for indications of settlement are performed. The

Structures Monitoring AMP (B.2.3.33) is used to manage cracking and distortion of the reinforced concrete elements of the HNP Groups 1-3, 6, 8, and 9 structures founded on soil and/or exposed to a groundwater/soil environments. There are no concrete Groups 5 and 7 components applicable to HNP. There are no concrete Group 4 components exposed to a soil environment.

As summarized in item number 3.5-1, 046, the item number is not applicable. HNP does not have a porous concrete subfoundation or relies on a dewatering system. HNP plant structures have reinforced concrete mat foundations founded on dense soil. Differential settlement of structures, which would be evidenced by cracking or warping of structures and structural components has not occurred at HNP.

The Structures Monitoring AMP (B.2.3.33) continues to inspect and monitor concrete structures within the scope of license renewal. Therefore, cracking and distortion due to settlement and reduction in foundation strength are managed by the Structures Monitoring AMP (B.2.3.33), but porous subfoundations and dewatering do not exist at HNP.

4. *Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible concrete areas of Groups 1–5 and 7–9 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

As summarized in item number 3.5-1, 047, the Structures Monitoring AMP (B.2.3.33) is used to manage increase in porosity and permeability, loss of strength of the reinforced concrete exposed to a water - flowing environment. The concrete work done for the Group 1, 2, 3, 8, and 9 structures at HNP was in accordance with ACI 318-63, Building Code Requirements for Reinforced Concrete, and ACI 301-66, Specifications for Structural Concrete for Buildings. Concrete aggregates conform to the requirements of ASTM C33, Standard Specification of Concrete Aggregates. Materials for concrete used in HNP concrete structures and components were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. Concrete structures are constructed of dense, durable mixture of sound coarse aggregates, fine aggregates, cement, and water. The cement used was either Type I, general use cement with no special properties, or Type II, low-alkali cement. There are no concrete Groups 4, 5, and 7 components exposed to a water - flowing environment applicable to HNP. Since the same concrete specification was used for all structures at HNP, including the Groups 1, 2, 3, 8, and 9 structures, these results are representative of the expected effects of leaching and carbonation of all structures within the scope of SLR.

HNP OE indicates leaching and calcium hydroxide buildup has been observed, but this aging mechanism did not impact intended functions of the structure. This condition is continuously trended as part of the Structures Monitoring AMP (B.2.3.33).

The foundations of HNP groups 1, 2, 3, 8, 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 as described in the Structures Monitoring AMP (B.2.3.33). The ground water at HNP is considered to be aggressive. Recent testing has shown that chlorides and sulfates levels are acceptable, however, the pH levels are below 5.5 at multiple locations throughout the site. The Structures Monitoring AMP (B.2.3.33) was enhanced to inspect and monitor below-grade, inaccessible concrete structural elements exposed to aggressive groundwater. This will include the performance of a baseline visual inspection prior to the SPEO at a minimum of one location which has experienced aggressive groundwater. The baseline inspection results will be used to conduct a baseline evaluation that will determine the additional actions (if any) that are warranted. Accessible areas of concrete structures exposed to an air – outdoor environment can be used as an indicator of concrete condition in a soil or groundwater environment. Any leaching or carbonation that is observed in accessible areas is evaluated for the potential impact on the function of concrete in inaccessible areas. When inaccessible structures are exposed because of excavation or modification, an examination of the exposed surfaces is performed.

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 ACI 349-85, "Code Requirements for Nuclear Safety-Related Concrete Structures," specifies the concrete temperature limits for normal operation or any other long-term period. The temperatures shall not exceed 66 °C (150 °F) except for local areas, which are allowed to have increased temperatures not to exceed 93 °C (200 °F). Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if any portion of the safety-related and other concrete structures exceeds specified temperature limits (i.e., general area temperature greater than 66 °C [150 °F] and local area temperature greater than 93°C [200°F]). Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. The acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

As summarized in 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 HNP licenses and is addressed in NUREG-2192. For plant areas of concern temperatures are normally maintained below the specified limits. Reduction of strength and modulus of concrete due to elevated temperatures are not expected to occur at HNP and do not require management.

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. The bulk drywell temperature is maintained by the primary containment cooling system.

Concrete structural components located inside the drywell are not subject to general area temperatures greater than 150ºF.

Insulation (thermal) is conservatively included within the scope of subsequent license renewal to assist in maintaining local concrete temperatures. The aging management of this insulation is provided by the External Surfaces of Mechanical Components AMP (B.2.3.23). 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 A.1 of this SRP-SLR).*

As summarized in item number 3.5-1, 049, loss of material (spalling, scaling) and cracking due to freeze-thaw, is applicable to HNP reinforced concrete Group 6 structure exposed to air – outdoor or groundwater/soil environments. At HNP, structures are located in a region where weathering conditions are considered moderate, as shown in ASTM C33-90, Figure 1. The concrete met all the standard code requirements. Air entrainment content conformed to the design requirements of ACI 211.1 and was determined by ASTM C231.

OE has not identified any significant loss of material (spalling, scaling) and cracking due to freeze-thaw of reinforced concrete Group 6 structure within the scope of license renewal. The Structures Monitoring AMP (B.2.3.33) includes inspection of concrete in the accessible areas. 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. Additionally, the Structures Monitoring AMP (B.2.3.33) performs opportunistic inspections to confirm the absence of aging effects by examining normally inaccessible structural components, when exposed because of excavation or modification, 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).

As summarized in item number 3.5-1, 050, cracking due to expansion and reaction with aggregates, is considered applicable to HNP reinforced concrete structures exposed to a groundwater/soil environment. The concrete work performed for Group 6 structure at HNP was in accordance with ACI 318-63, Building Code Requirements for Reinforced Concrete, and ACI 301-66, Specifications for Structural Concrete for Buildings. 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, organic matter, and other deleterious substances. Tests and petrographic examinations of the concrete were performed according to ASTM C289-64 and ASTM C295.

OE has not identified any evidence of reaction with aggregates at HNP. Nevertheless, the Structures Monitoring AMP (B.2.3.33) continues to inspect and monitor concrete structures for cracking, including hairline and patterned cracking, which are typical evidence of reaction with aggregates, such as alkali-silicate reaction (ASR). 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. Opportunistic inspections will be performed to confirm the absence of aging effects by examining normally inaccessible structural components, when exposed because of excavation or modification. If cracking due to expansion and reaction with aggregates were significant, pattern cracking would be expected over the accessible surfaces. This has not occurred. This provides objective evidence that cracking associated with expansion due to reaction with aggregates has not yet occurred. Considering the age of HNP, the possibility of occurrence becomes unlikely. Nevertheless, HNP will continue to look for indications of cracking associated with expansion due to reaction with aggregates. 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 Structures Monitoring AMP (B.2.3.33).

Since cracking due to expansion and reaction with aggregates occurs at a comparatively slow rate, the required five-year inspection frequency, of the Structures Monitoring AMP (B.2.3.33), is adequate to address any significant concrete damage due to cracking due to expansion and reaction with aggregates before a loss of intended function. As a result, the Structures Monitoring AMP (B.2.3.33) is expected to adequately manage the cracking due to expansion and reaction with aggregates that could occur in inaccessible reinforced concrete areas of Group 6 structure.

3. *Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of Group 6 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if leaching is*

observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

As summarized in item number 3.5-1, 051, the Structures Monitoring AMP (B.2.3.33) is used to manage increase in porosity and permeability, loss of strength of the reinforced concrete exposed to a water - flowing environment. The concrete work performed for the Group 6 structure at HNP was in accordance with ACI 318-63, Building Code Requirements for Reinforced Concrete, and ACI 301-66, Specifications for Structural Concrete for Buildings. Concrete aggregates conform to the requirements of ASTM C33, Standard Specification of Concrete Aggregates. Materials for concrete used in HNP concrete structures and components were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. Concrete structures are constructed of dense, durable mixture of sound coarse aggregates, fine aggregates, cement, and water. The cement used was either Type I, general use cement with no special properties, or Type II, low-alkali cement.

HNP OE indicates leaching and calcium hydroxide buildup has been observed, but this aging mechanism did not impact intended functions of the structure. The condition is continuously trended as part of the Structures Monitoring AMP (B.2.3.33). This OE was not on a Group 6 structure.

The foundation of HNP Group 6 plant structure is 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 as described in the Structures Monitoring AMP (B.2.3.33) . The ground water at HNP is considered to be aggressive. Recent testing has shown that chlorides and sulfates levels are acceptable, however, the pH levels are below 5.5 at multiple locations throughout the site. The Structures Monitoring AMP (B.2.3.33) was enhanced to inspect and monitor below-grade, inaccessible concrete structural elements exposed to aggressive groundwater which will include the performance of a baseline visual inspection prior to the SPEO at a minimum of one location which has experienced aggressive groundwater. The baseline inspection results will be used to conduct a baseline evaluation that will determine the additional actions (if any) that are warranted. Accessible areas of concrete structures exposed to an air – outdoor 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.

3.5.2.2.2.4 Cracking due to Stress Corrosion Cracking, and Loss of Material due to Pitting and Crevice Corrosion

Cracking due to SCC and loss of material due to pitting and crevice corrosion could occur in: (i) Group 7 and 8 SS tank liners exposed to standing water and (ii) SS and aluminum alloy support members, welds, bolted connections, or support anchorage to building structure exposed to air or condensation (see SRP-SLR Sections 3.2.2.2.2, 3.2.2.2.4, 3.2.2.2.8, and 3.2.2.2.10 for background information).

For Group 7 and 8 SS tank liners exposed to standing water, further evaluation is recommended of plant-specific programs to manage these aging effects. The *acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

For SS and aluminum alloy support members, welds, bolted connections, support anchorage to building structure exposed to air or condensation, the plant-specific OE and condition of the SS and aluminum alloy components are evaluated to determine if the plant-specific air or condensation environments are aggressive enough to result in loss of material or cracking after prolonged exposure. The aging effects of loss of material and cracking in SS and aluminum alloy components is not applicable and does not require management if: (i) the plant-specific OE does not reveal a history of pitting or crevice corrosion or cracking and (ii) a one-time inspection demonstrates that the aging effects are not occurring or that an aging effect is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA. Visual inspections conducted in accordance with GALL-SLR Report AMP XI.M32, "One-Time Inspection," are an acceptable method to demonstrate that the aging effects are not occurring at a rate that affects the intended function of the components. One-time inspections are conducted between the 50th and 60th year of operation, as recommended by the "Detection of Aging Effects" program element in AMP XI.M32. If loss of material or cracking has occurred and is sufficient to potentially affect the intended function of SS or aluminum alloy support members, welds, bolted connections, or support anchorage to building structure, either: (a) enhancing the applicable AMP (i.e., GALL-SLR Report AMP XI.S3, "ASME Section XI, Subsection IWF," or AMP XI.S6, "Structures Monitoring"), (b) conducting a representative sample inspection consistent with GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or (c) developing a plant-specific AMP are acceptable programs to manage loss of material or cracking (as applicable). Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combinations which are not susceptible to SCC when used in structural support applications include 1xxx series, 3xxx series, 6061-T6x, 6063-T6, and 5454-x. For these alloys and tempers, the susceptibility of cracking due to SCC is not applicable. If these alloys or tempers have been used, the SLRA states the specific alloy or temper used for the applicable in scope components.

As summarized in item number 3.5-1, 052, this item number is not applicable to HNP. HNP does not have Group 7 and 8 stainless steel tank liners exposed to standing water.

As summarized in item number 3.5-1, 099, loss of material and cracking is considered applicable to HNP stainless steel ASME Class 1 piping supports, and ASME Class 2 and 3 piping and ducts supports exposed to an air – indoor uncontrolled environment. Loss of material is applicable to HNP stainless steel support members, welds, bolted connections, and support anchorage to building structure exposed to an air – indoor uncontrolled environment. An aluminum material type is not applicable for this item number at HNP. The ASME Section XI, Subsection IWF AMP (B.2.3.30) is used to examine the ASME Class 1 piping supports, and ASME Class 2 and 3 piping and ducts supports aligned to this item number. The Structures Monitoring (B.2.3.33) program has been substituted for the One-Time Inspection (B.2.3.20) and is used to manage loss of material of the stainless steel support members, welds, bolted connections, and support anchorage to building structure exposed to an air – indoor uncontrolled environment in primary containment.

As summarized in item number 3.5-1, 100, loss of material due to pitting and crevice corrosion, and cracking due to SCC is considered applicable to HNP stainless steel jacketing and fire doors (hinges) exposed to an air – indoor uncontrolled environment, and aluminum blowout panels, new fuel storage racks, cover plates: pull boxes, cable tray, jacketing, and fire doors (molding, accessories), exposed to air – indoor uncontrolled and air – outdoor environments. The Structures Monitoring AMP (B.2.3.33) is used to examine the components aligned to this item number except for the component type jacketing. The jacketing component type will be examined by the External Surfaces Monitoring of Mechanical Components AMP (B.2.3.23).

3.5.2.2.2.5 Cumulative Fatigue Damage due to Fatigue

Evaluations involving time-dependent fatigue, cyclical loading, or cyclical displacement of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports are TLAAs as defined in 10 CFR 54.3 (TN4878) only if a CLB fatigue analysis exists. The TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.3, "Metal Fatigue," and/or Section 4.7, "Other-Plant Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.

As summarized in item number 3.5-1, 053: The only fatigue analysis related to plant structures is for fatigue of cranes (crane cycle limits) and for portions of the primary containment. Management of fatigue of cranes (crane cycle limits) is addressed in item number 3.3-1, 001. Management of cumulative fatigue damage to primary containment is addressed in item number 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 RV support/pedestal structure. Data related to the effects and significance of neutron and gamma radiation on concrete mechanical and physical properties is limited, especially for conditions (dose, temperature, etc.) representative of light-water reactor (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 Gray (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 the aging *effects of irradiation if the estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (fluence cutoff energy E > 0.1 MeV) or gamma radiation exceeds the respective threshold level during the subsequent period of extended operation that could affect intended functions. Higher fluence or dose levels may be allowed in the concrete if tests and/or calculations are provided to evaluate the reduction in strength and/or loss of mechanical properties of concrete from those fluence levels, at or above the operating temperature experienced by the concrete, and the effects are applied to the design calculations. Supporting calculations/analyses, test data, and other technical basis are provided to estimate and evaluate fluence levels and the plant-specific program. The acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

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 reactor shield wall (also referred to as the sacrificial shield wall) 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 is the reactor shield wall whose primary function is to protect equipment inside the drywell against radiation and thermal effects. The reactor shield is composed of two steel cylinders filled with concrete. The concrete of the reactor shield wall is not credited for structural support therefore, any potential cracking, loss of strength or change in mechanical properties in the concrete of the reactor shield wall will not impact its intended function and does not require further evaluation.

The reinforced concrete reactor vessel pedestal performs a structural support intended function and therefore needs to be evaluated for aging effects of irradiation. The elevation of the top of the concrete pedestals for both units are located slightly below vessel 0 (lowest elevation of the reactor vessel) and well below the active core region. Figures 3.5.2.2.2.6-1 and 3.5.2.2.2.6-2 show the elevation of the reactor vessel pedestals relative to the vessel 0 location, core, and core mid-plane for Units 1 and 2. Table 3.5.2.2.2.6-1 shows the exact elevations used for these key locations. The concrete pedestals for HNP Units 1 and 2 have been evaluated for the potential aging effects associated with neutron and gamma irradiation.

Table 3.5.2.2.2.6-1: Reactor Vessel and Pedestal Elevations

Location	Unit 1	Unit 2
Elevation, Top of RV Pedestal	141 ft - 1 in	142 ft - 2 in
Elevation, Vessel 0	143 ft - 6 in	143 ft - 6 in
Elevation, Active Core Mid-Plane	~167 ft	~167 ft
Height, Active Core Region	12 ft	12 ft

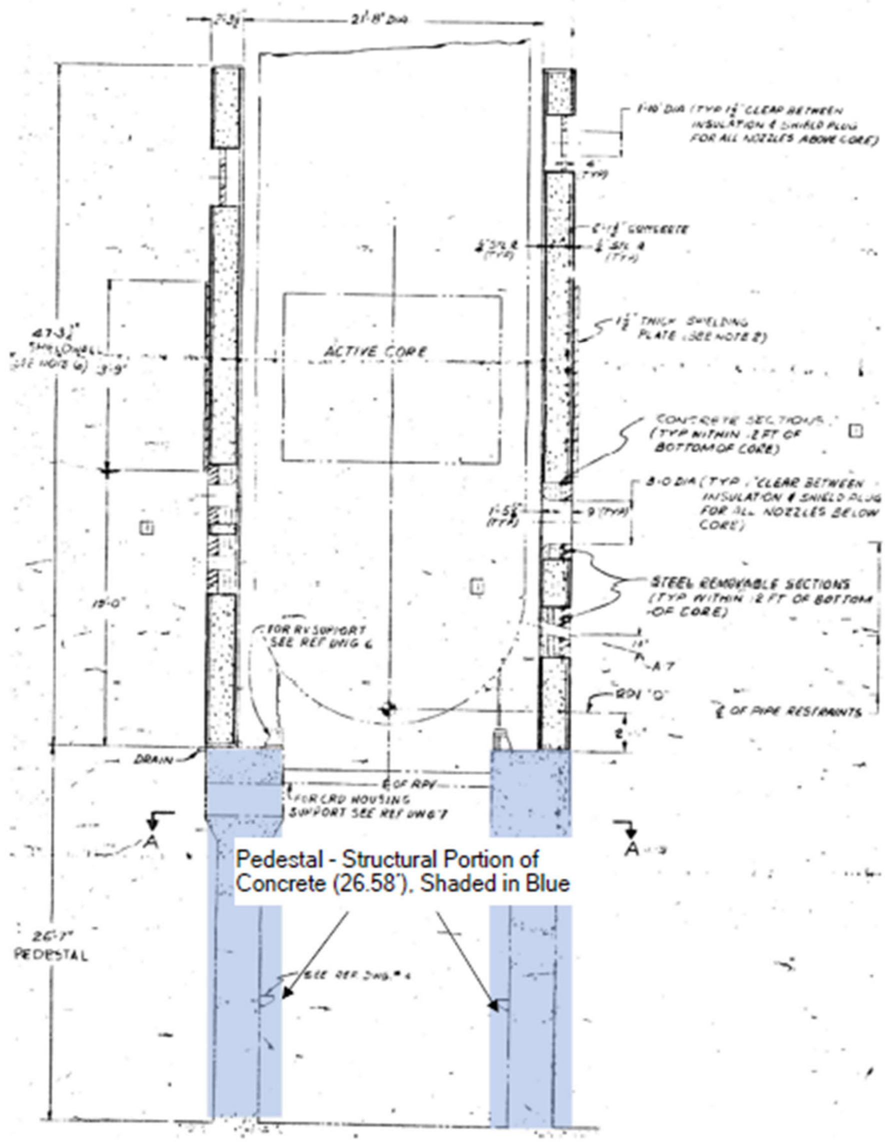


Figure 3.5.2.2.2.6-1: Section Through Hatch Unit 1 Reactor Shield Wall and Pedestal

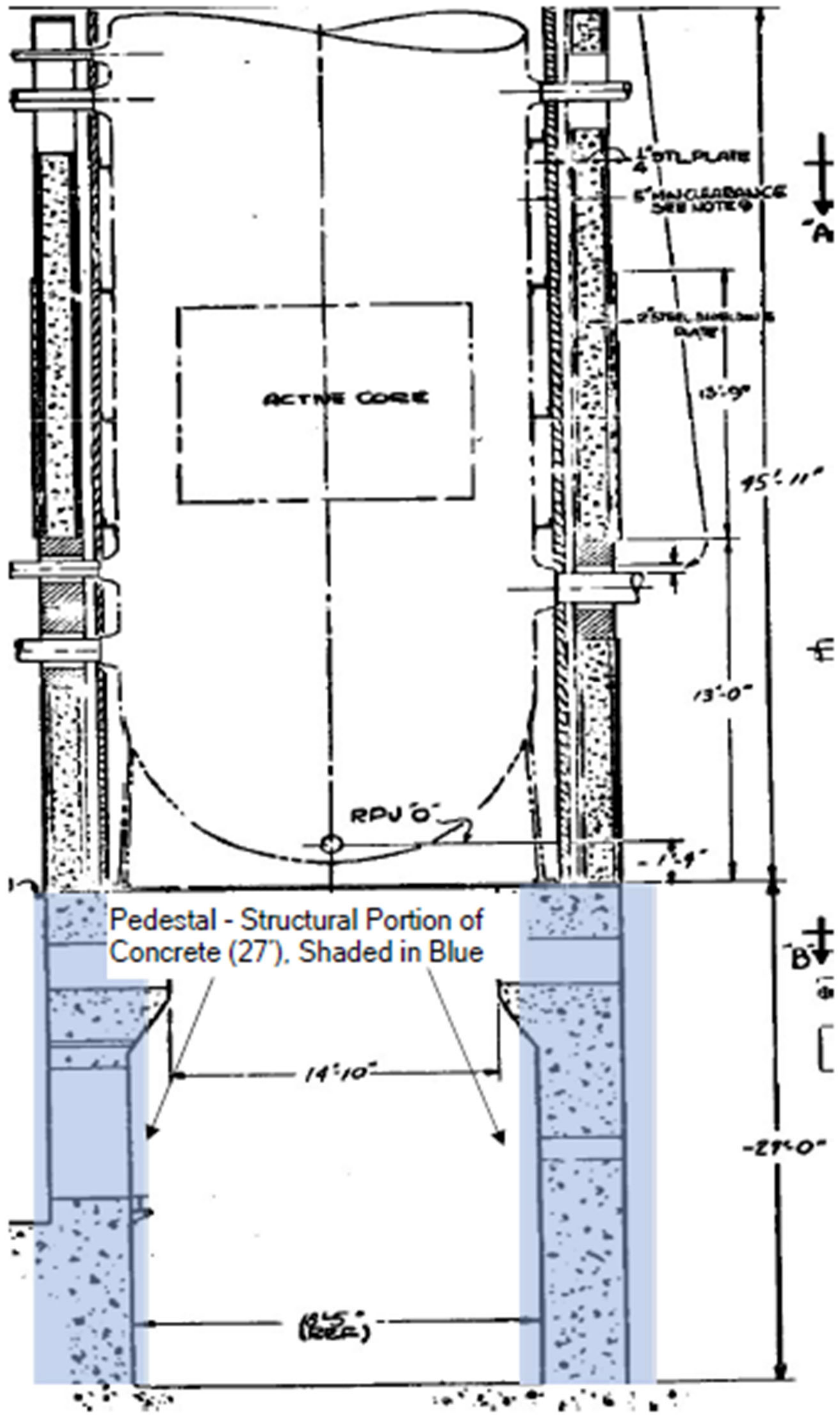


Figure 3.5.2.2.2.6-2: Section Through Hatch Unit 2 Reactor Shield Wall and Pedestal

Neutron Fluence and Gamma Dose

The neutron fluence and gamma dose were calculated for each reactor at bounding locations at the inside face of the concrete reactor shield wall. The bounding values occur roughly at elevations near the reactor active core mid-plane. The calculated values are for reactor operation of 68.6 EFPY for Unit 1 and 66 EFPY for Unit 2 which corresponds to the expected operation through the SPEO. The best-estimate epi-fast neutron fluence for the reactor shield wall inner steel cladding is calculated from the Hatch Unit specific RPV fluence models. The RPV epi-fast neutron (E> 0.1 MeV) fluence was calculated using the Radiation Analysis Modeling Application (RAMA) Fluence Methodology.

Table 3.5.2.2.2.6-2: Bounding Fluence and Peak Gamma Dose at Reactor Sacrificial Shield Concrete Wall

Unit	Elevation (1) (in)	Concrete Depth (2) (in)	Epi-Fast Neutron Fluence (E > 0.1 MeV) (n/cm^2)	Gamma Dose (Gy)
Unit 1	285.3	0.0	3.91E+18	2.53E+8
Unit 2	267.1	0.0	4.48E+18	2.99E+8

Notes: (1) Elevation from vessel 0 elevation which is at the inside surface of the lowest point in the reactor vessel. Location of peak value is close to mid-plane of active core region

(2) Depth from inside surface of the concrete reactor shield wall

The neutron fluence, even at these bounding locations in concrete that is not credited for structural support, is below the defined threshold where damage to concrete occurs (1×10^{19} neutrons/cm^2). Therefore, no further evaluation of neutron fluence for concrete in the pedestal is warranted as it is bounded by the fluence at the biological shield wall. However, the calculated values for gamma dose at these bounding locations in the biological shield wall exceed the defined threshold of 1×10^8 Gy, therefore, further evaluation is required to determine if the structurally credited concrete in the pedestal area is adversely affected.

EPRI report 3002011710 “Irradiation Damage of the Concrete Biological Shield: Basis for Evaluation of Concrete Biological Shield Wall for Aging Management” was used to determine the variation of radiation levels along the height of the active core. Figures 2-6 and 2-7 from the EPRI report provide generic curves developed for a typical 3-loop pressurized water reactor (PWR) plant. This approach is conservative; as gamma dose from boiling water reactor (BWR) plants are not expected to be greater than PWRs. Gamma dose is assumed to be proportional to flux, for the purpose of conservatively estimating the radiation exposure of the concrete. The flux distribution from the EPRI generic curves was scaled using the data in Table 3.5.2.2.2.6-1. A plot was made of the normalized gamma dose versus the height relative to the active core mid-plane and extended to show the top of the pedestal area. Conservatively the ratio of gamma flux below the core region was set equal to the last data point on the curve for the shield wall concrete. The Unit 1 gamma dose is capped at 8.86×10^9; which is below the threshold limit of 1×10^{10} Rad. The Unit 2 gamma dose is capped at 1.05×10^{10} Rad, however this gamma dose drops below the threshold value at an elevation 100 inches from the core mid-height. As shown in Figure 3.5.2.2.2.6-2, the top of the Unit 2 pedestal is sufficiently removed from active core (321 inches below the core midplane).

<u>Radiation-Induced Volumetric Expansion (RIVE) Considerations</u>

Radiation-induced volumetric expansion (RIVE) is a degradation mechanism in which the concrete volume increases as a result of heating and morphology changes induced from gamma irradiation. For concrete subjected to high values of gamma dose, there is also the potential for a decrease in compressive strength. Because the reactor shield wall does not provide a structural intended function, potential RIVE impacts to concrete material properties is not a concern. The potential impact of concrete volumetric expansion on the reactor shield wall steel liner is addressed in Section 3.5.2.2.2.8.

In both Units, the elevation where the gamma fluence is reduced below the threshold for concrete damage is at an elevation in the containment that is above the elevation of the reactor pedestal, and therefore the concrete credited for structural support is not exposed to gamma irradiation sufficient to adversely affect the concrete strength or mechanical properties. No additional aging management of the concrete RV pedestal beyond the current Structures Monitoring (B.2.3.33) AMP is required as a result of irradiation effects on concrete.

3.5.2.2.2.7 Loss of Material, and/or Changes in Material Properties Due to Weathering, Chemical Degradation, Insect Infestation, Repeated Wetting and Drying, or Fungal Decay

Loss of material and/or changes in material properties due to weathering, chemical degradation, insect infestation, repeated wetting and drying, or fungal decay could occur in standing wooden poles. Their vulnerability to decay is generally dependent on geographical location and site-specific characteristics and conditions. Factors affecting the service life of the wooden poles are the species of wood, type and thoroughness of treatment, geographical location, and soil conditions.

Further evaluation is recommended to determine the plant-specific AMP or plant-specific enhancements to an existing AMP(s) required to manage the effects of aging for wooden poles during the subsequent period of extended operation. A plant-specific AMP or plant-specific enhancements to an existing AMP(s) is acceptable if visual inspections are supplemented with appropriate additional examination methods or techniques, at a frequency capable of detecting the presence and extent of aging effects that are expected in portions of wooden poles that are below-grade and/or internally before there is a loss of intended function. This should account for the decay/deterioration expected to occur at the site based on geographical location and site-specific characteristics and conditions. The plant-specific AMP or plant-specific enhancements to an existing AMP(s), should provide appropriate acceptance criteria and corrective actions, consistent with industry guidelines. The acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

As summarized in item number 3.5-1, 101, this item number is not applicable to HNP. There are no wooden poles in scope of license renewal at HNP.

3.5.2.2.2.8 Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete

Combined effects of aging associated with neutron radiation exposure could occur in the RV structural support assembly components and materials in BWRs and PWRs. The steel components of the RV structural support assembly (including associated weldments and bolted connections) are made of ferritic carbon or low alloy steels, and the combined effects of aging for these steel components include, but are not limited to, reduction in fracture toughness, loss of material, loss of preload, and distortion that could result in loss of intended function. Examples of RV steel structural support components are RV steel girder and column supports, RV steel support skirt, and neutron shield tanks. For nonconcrete, nonmetallic materials (e.g., Lubrite® lubricant) and nonconcrete, nonferrous materials (e.g., manganese bronze alloy) associated with the RV structural support assembly, effects of aging due to radiation exposure could also result in loss of intended function. Further evaluation of the RV structural support assembly as a whole is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to selected GALL-SLR AMPs to manage combined effects of aging, such that intended function(s) of the RV structural support assembly as a whole is maintained consistent with the CLB for the subsequent period of extended operation (SPEO).

The acceptance criteria for a plant-specific AMP or enhancements to GALL-SLR AMPs for ongoing management of potential combined effects of aging are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR). The combined effects of aging associated with irradiation (i.e., reduction in fracture toughness, loss of material, loss of preload, and distortion) in the RV structural support assembly components may be addressed by analysis or by augmented ongoing examinations and inspections for the effects of aging, as needed, or a combination of these, during the SPEO. Any analysis should include conservatisms in the technical basis (or bases) that account for uncertainties in the evaluation parameters (e.g., fluence, initial nil-ductility temperature, and fracture toughness).

Prior to any analysis, 1 evaluation of the physical conditions through physical examination of the RV structural supports is essential for assessing whether the structural integrity of the RV structural support assembly (other than concrete) is affected by potential combined effects of radiation exposure that include reduction in fracture toughness, corrosive environment (boric acid), temperature, cyclic loading, and applied stresses (including weld residual and/or fabrication stresses). Inservice inspection for flaws in portion of support beams embedded in the concrete biological shield wall may be unattainable; however, inspection records indicating distortions may shed light on the likelihood of significant flaws that may have developed inside the concrete. One or more existing AMPs (e.g., ASME Section XI, Subsection IWF AMP, Boric Acid AMP) may be credited for this physical examination. Following the physical examination, NUREG-1509, "Radiation Effects on Reactor Pressure Vessel Supports," (Ref. 26) provides one acceptable methodology (with the exception of the structural consequence analysis approach in Section 4.5 of the report) for evaluating the RV steel structural support assembly for reduction in fracture toughness due to irradiation embrittlement during the SPEO. An initial screening methodology in NUREG-1509 (Section 4.2) *provides one acceptable method for initial assessment for the potential for irradiation embrittlement of the RV steel support system components based on the plant-specific reactor support configuration, plant-specific materials, and plant-specific state of stress. If irradiation embrittlement is a possibility based on this initial screening, an evaluation of the RV steel structural support assembly for a reduction in fracture toughness can be based on a fracture mechanics analysis or a transition temperature analysis (relative to the lowest operating or service temperature of the RV steel structural support component), such as those outlined in Section 4.3 of NUREG-1509, or an accurate analysis such as that outlined Section 4.4 of NUREG-1509. Applications that rely on the use of NUREG-1509 generic nil-ductility transition temperature (NDTT) values in lieu of those from plant specific materials testing need to include additional justification that the NUREG-1509 generic NDTT values are representative of the plant-specific materials of the RV steel structural support assembly components; these applications will be reviewed on a case-by-case basis. In such a case, applicants can use a bounding approach in their fracture analysis, selecting the most conservative values from available data and references, other further evaluation methodologies, including augmented inspections and examinations.*

In the event the applicant pursues augmented ongoing examinations and inspections as needed from one or more GALL-SLR AMPs that help detect the effects of aging for the RV structural support assembly components, including but not limited to cracking, loss of material, loss of preload, and permanent distortion, the details of these augmented ongoing examinations and inspections need to be provided as part for this further evaluation so that the effects of aging are adequately managed consistent with 10 CFR 54.21(a)(3) and that the intended function(s) remain consistent with the CLB for the SPEO.

A plant-specific AMP or plant-specific enhancements to selected GALL-SLR AMPs may not be necessary for the RV steel structural support components if either the initial screening criteria (such as those in Section 4.2.4 of NUREG-1509) or the evaluation criteria (such as those in Section 4.3 or Section 4.4 of NUREG-1509) are satisfied based on plant-specific evaluations. For the radiation exposure criterion in Section 4.2.4 of NUREG-1509, the plant-specific radiation exposure level at a specific location in the RV steel structural supports can be considered low if the radiation exposure damage level is 2×10^{-5} displacements per atom (dpa) or less, consistent with the upper-bound embrittlement shift curve specified in Figure 3-1 of NUREG-1509 and considering an energy spectrum of E > 0.1 MeV. The ASTM International Standard E693-17 (Ref. 28) provides a methodology for calculating damage (i.e., dpa) for iron and ferritic low alloy steels.

The radiation exposure evaluation of the RV structural support assembly as a whole should be for an energy spectrum of E > 0.1 MeV and use conservative assumptions to estimate the levels of neutron fluence exposure to calculate the projected dpa damage for the SPEO. Evaluation methodologies that have been endorsed by the NRC may be used, but justifications should be provided for their applicability beyond the basis for qualification and approval (e.g., differences in areas of exposure and location(s) for which a methodology was benchmarked against). For evaluation methodologies not previously reviewed or endorsed by the NRC, the applicant provides a detailed description of the analysis methodology and how it was qualified to determine its adequacy for use.

Based on the results of the radiation exposure evaluation, the applicant evaluates the structural integrity of the RV steel structural support components for a reduction in fracture toughness if the radiation exposure damage level exceeds 2 × 10-5 dpa. Additionally, the applicant considers effects of aging associated with irradiation working in synergy with reduction in fracture toughness of the RV steel structural support components such that these components will maintain their intended function(s) consistent with the CLB through the SPEO. The structural integrity evaluation should include all RV structural support design basis load combinations in the UFSAR. The irradiation embrittlement predictions of the RV steel structural support assembly components consider their chemical composition to determine the influence of alloying elements, such as copper, nickel, and phosphorous, on reduction in fracture toughness. For nonconcrete, nonmetallic, nonferrous components and/or materials, the applicant provides supporting technical information and data used to determine their integrity against loss of intended function as a result of radiation exposure and to determine the need for a plant-specific AMP or enhancements to selected GALL-SLR AMPs to manage the combined effects of aging associated with irradiation during the SPEO.

Risk-informed, performance-based (RIPB) principles can be used in the evaluation of the RV steel structural support assemblies with safety being the ultimate objective to maintain RV support intended function consistent with the CLB during the SPEO. RIPB relies on damage tolerance and performance outcomes based on CLB engineering loading demand parameters for events of defined magnitude with uncertainty estimates. This means the applicant ensures that after examination or inspection the results are assessed and uncertainty in the evaluation parameters (e.g., fluence, initial nil-ductility temperature, fracture toughness) are incorporated, margins remain in load-bearing capacity in the RV steel structural support assembly system, such that if performance criteria are not met a safety concern will not develop during the SPEO. Applicants using RIPB principles need data to support their determination of reasonable assurance that the RV steel structural support assembly system will fulfill its intended function through the end of the SPEO. Thus, assumptions in the RIPB evaluation of the RV steel structural support assemblies reflect in situ conditions for material, environment, and component behavior subject to noted uncertainties. The RIPB methodology could be fulfilled, for example, by a combination of ongoing inspections and fracture mechanics with adjustment to uncertainties involved in estimation of damage tolerance. Damage tolerance is a method of assessing the ability of a RV steel structural support assembly component to perform its intended function in the presence of a defect, damage, or flaw. Specifically, damage tolerance is assessing how damage to an RV steel structural support assembly component is tolerated when it fails and evaluating the subsequent redistribution of loads within the RV steel structural support assembly.

As summarized in Table 3.5-1, item 3.5-1, 102, the potential for loss of fracture toughness due to the combined effects of irradiation is an aging effect requiring further evaluation for the steel portions of the reactor shield wall (also referred to as the sacrificial shield wall) and the steel reactor vessel support assembly. The reactor vessel (RV) support structures at HNP are described in FSAR sections 4.2.4 and K.7 for Unit 1 and section 5.4.6.3.3 for Unit 2. Table 3.5-1, item 3.5-1, 103 is not applicable; as the HNP RV support design does not include sliding supports.

The reactor vessel is supported by a steel skirt. The top of the skirt is welded to the bottom of the RV. The skirt is then supported by a concrete pedestal encased inside two concentric steel shells. The bottom of the pedestal is anchored to the base slab by anchor bolts which transfer the loads to the reactor building foundation. The RV support assembly also consists of a ring girder and the various bolts, shims, and set screws necessary to position and secure the assembly between the reactor vessel support skirt and the support pedestal. The ring girder is fabricated of ASTM A-36 structural steel.

Vessel stabilizers are provided to transmit seismic and jet reactor forces to supporting structures. They also limit horizontal vibration. The vessel stabilizers connect the reactor vessel to the top of the reactor shield wall and are located well above the active core region of the RV. Full-penetration welds attach stabilizer brackets to the RV at evenly spaced locations around the vessel below the flange. Each vessel stabilizer consists of a stabilizer rod, threaded at the ends; springs, washers, a nut, a plate, and a bumper bracket with tapered shims. The stabilizer assemblies are also referred to as the star truss.

The reactor shield wall consists of 12 built-up steel columns with a steel liner plate welded on both sides of the column flanges. Another liner plate is provided on the outside flange of the core area for radiation shielding. Intermediate ring beams are provided at various levels to accommodate the restraints. The reactor shield wall is rigidly connected at the base to the RV pedestal and laterally supported by a star truss (stabilizers) at the top of the reactor shield wall. The star truss transfers forces from the RV and the shield wall to the drywell shield concrete through lugs in the drywell.

Table 3.5.2.2.2.8-1 provides elevations for the components and general locations described above.

Table 3.5.2.2.2.8-1 – RV and Support Elevations

Component / Location	Unit 1 Elevation	Unit 2 Elevation
Top of RPV Pedestal	141 ft - 1 in	142 ft – 2 in
Vessel 0 (lowest point in the RPV)	143 ft - 6 in	143 ft – 6 in
Active Core Mid-plane	~167 ft	~167 ft
Stabilizers (star truss)	188 ft - 5 in	188 ft - ½ in

* The active core height is 12 feet for both Unit 1 and Unit 2.

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 the radiation embrittlement is not an issue for reactor vessel support skirts. In addition to NUREG-1509, BWRVIP-342, Aging Management of Reactor Vessel Support for Extended Operation, 2022 (EPRI Report 3002020999), has recently been prepared to address irradiation of the RV supports using the methodologies described in NUREG-1509. Therefore, BWRVIP-342 was also used to provide additional clarification. BWRVIP-342 was referenced for guidance in interpreting the effects of irradiation on hardening and embrittlement of steel supports in the calculation of record for HNP. The information referenced in

BWRVIP-342 is independent of the HNP RV support structure configuration. Data cited in BWRVIP-342 has no bearing on actual design basis transients and the calculated design loads used in the analysis for HNP. As listed in Figure 3-1 of the EPRI document, HNP is within the locus of GE-designed BWRs for which bounding design transients, maximum design loads and operating conditions are evaluated in the report.

As stated in NUREG-1509, the plant-specific radiation exposure level at a specific location in the RV steel structural support can be considered low if the radiation exposure damage level is 2 x 10^{-5} dpa or less, consistent with the upper-bound embrittlement shift curve specified in Figure 3-1 of NUREG-1509 and considering an energy spectrum of E > 0.1 MeV. HNP reactor vessel fluence and iron dpa calculations, projected for 68.6 EFPY (Unit 1) and 66 EFPY (Unit 2), were performed using combination of EPRI RAMA Fluence Methodology, TransWare's TRANSFX-TRANSRAD Nuclear Analysis Software (TRANSRAD), and the SCALE-ORIGEN (ORIGEN) software distributed by the Radiation Safety Information Computational Center (RSICC) at Oak Ridge National Laboratory. The RAMA and TRANSRAD transport modules have been validated against the neutron fluence benchmarks cited in Regulatory Guide 1.190 with no discernible bias in results. The best-estimate fast neutron fluence and iron dpa for the reactor shield inner cladding are calculated from the HNP Unit 1 and Unit 2 RPV fluence model. The RPV fast fluence was calculated using the RAMA Fluence Methodology.

The bounding value of dpa, located roughly near the active core mid-height, and calculated at the outer radius of the RV, is shown in Table 3.5.2.2.2.8-2 for each Unit.

Table 3.5.2.2.2.8-2 – Bounding DPA Values

Unit	dpa	Location above Vessel 0
1	7.96 x 10^{-4} dpa at 68.6 EFPY	295.8 in (~El. 168 ft – 2 in)
2	7.53 x 10^{-4} dpa at 66.0 EFPY	290.9 in (~El. 167 ft – 9 in)

<u>Reactor Vessel Skirt, Pedestal Steel, and Stabilizers</u>

Due to the bounding dpa levels exceeding the threshold of 2 x 10^{-5} dpa for both Unit 1 and Unit 2, variation of the dpa over the height of the active fuel region and reactor shield wall was calculated. Assuming proportionality between neutron fluence and dpa, the projected SPEO dpa value falls below the threshold for the structural stress approximately 100 inches above and below the mid-core height. The top portion of the Unit 1 support skirt is located approximately at elevation 148 feet and 3 ½ inches and the stabilizers are located at elevation 188 feet and 5 inches. The top portion of the Unit 2 support skirt is located approximately at elevation 148 feet and 3 ½ inches and the stabilizers are located at elevation 188 feet and ½ inch. The reactor vessel support skirt and lateral supports (stabilizer structure) are located well below the active fuel and above the active fuel, respectively, and both components are below the threshold value for dpa of 2 x 10-5 for embrittlement of steel at 68.6 EFPY for Unit 1 and 66 EFPY for Unit 2. Figures 3.5.2.2.2.6-1 and 3.5.2.2.2.6-2 show the reactor vessel active core region.

Although the integrity of the reactor vessel supports (RV skirt, pedestal steel, and stabilizers) is assured, with dpa below the threshold at the top of the support skirt and at the stabilizers, the current ASME Section XI, Subsection IWF (B.2.3.30) AMP inspection of the RV support will also confirm there is no visible evidence of a loss of fracture toughness (e.g., cracking) during the SPEO.

Reactor Shield Wall Structural Steel

As described above and in FSAR sections 12.2.15.2.11 and 3.8.3.1 for Unit 1 and Unit 2, respectively, the reactor shield wall consists of 12 inch to 27 inch WF-steel columns continually tied by a 3/8 inch thick steel plate on the inside and outside flanges of the columns from top to bottom. The inside liner plate is connected by a complete penetration weld to the column flanges.

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 reactor shield wall across from the active core height are addressed.

NUREG-1509 maps an approach for evaluating radiation embrittlement of RV support steel using the following key criteria. If these criteria are met, radiation embrittlement would be considered negligible, and its integrity can be reasonably assured with no need for further investigation.

- Criterion 1: The end-of-life radiation exposure at the reactor shield wall is low (2.0×10^{-5} displacements per atom (dpa) or less).
- Criterion 2: The nil-ductility transition (NDT) temperature of the reactor shield wall steel is below the minimum operating temperature.
- Criterion 3: The peak tensile stresses are 6 ksi, or less.

In the event radiation exposure of the steel exceeds the embrittlement threshold (i.e., criteria 1 is not met), NUREG-1509 recommends a fracture mechanics evaluation also be performed.

The same logic was used to assess radiation embrittlement of the HNP reactor shield wall steel.

Criteria #1

As shown in Table 3.5.2.2.2.8-2 the bounding dpa, occurring at approximately the mid-height of the active fuel, is above the 2×10^{-5} threshold for embrittlement of steel, for both Unit 1 and Unit 2. Therefore, a fracture mechanics evaluation was conservatively performed for all reactor shield wall structural steel evaluations in accordance with NUREG-1509.

Criteria #2

NDT evaluations were not credited. A fracture mechanics evaluation in accordance with NUREG-1509 is credited instead.

Criteria #3 and Fracture Mechanics

To evaluate the stress levels in the reactor shield wall, the entire shield wall structure was modeled in ANSYS, including the stabilizers (star truss), portions of the liner, and restraints. The finite element analysis in support of this fracture mechanics evaluation utilized original design basis inputs. Of the 11 total load cases in the analysis, the controlling load combination presented in the design basis stress analysis model and implemented in the SLRA stress analysis is as shown in Table 3.5.2.2.2.8-3:

Table 3.5.2.2.2.8-3: Stress Analysis Result Summary

Unit	Load Case	Location	Max Total Tensile Stress Along the Active Core Region with Inner Liner Plate Only
1	#6: 732.5 kip force at member	At two locations at elevation 168 ft	7.47 ksi
2	#11: 1850 ft-kip moment and 730 kip force at member	Elevation 168 ft at 72 degrees	10.52 ksi

The maximum tensile stress (including membrane, bending, and peak stress) at the inner liner plate is greater than the 6 ksi threshold set forth in NUREG-1509 for both Unit 1 and Unit 2. Therefore, additional fracture toughness analysis is required.

The lower bound K_{IC} fracture toughness from industry literature (NUREG-3009 and Fracture Toughness and CVN Date for A36 Steel with Wet Welding, 2017, by Méndez, Gerardo Terán, et. al.) for the ASTM A36 steel (32 ksi-in$^{1/2}$) used for construction of the reactor shield wall was used to provide a conservative and bounding evaluation of the ability of the reactor shield wall to continue to perform its intended function through the SPEO. The limiting stress intensity factor (K_I) of 26.5 ksi-in$^{1/2}$ for Unit 1 and 28.4 ksi-in$^{1/2}$ for Unit 2 (calculated in accordance with the guidance in NUREG-1509) remains below the bounding lower material fracture toughness value. The parameters utilized in this evaluation were conservatively selected and constructed as appropriate for a typical 1/4T (quarter of the reactor shield wall liner thickness) assumed flaw utilized by ASME Section XI, Appendix G evaluations (similar to those utilized for reactor pressure vessel integrity). Therefore, the decrease in fracture toughness to the end of the SPEO will not affect the stability and operability of the reactor shield wall and liner.

<u>Radiation-Induced Volumetric Expansion (RIVE) Considerations</u>

Radiation-induced volumetric expansion (RIVE) is a degradation mechanism in which the concrete volume increases as a result of heating and morphology changes induced from gamma irradiation. The deformation of the concrete can remain permanently and therefore can modify the loading of a structure being analyzed. For the arrangement of the reactor shield and the limiting inner liner, RIVE serves to induce compressive stresses on the liner, reducing the applicable tensile operating stress. For conservatism of the analysis, RIVE has therefore not been included and represents additional available margin, even for small RIVE effects.

Accordingly, the potential effects of irradiation on the steel elements of the biological shield, including the welding material, are not significant. While the integrity of the biological shield is assured, conservatively the current Structures Monitoring (B.2.3.33) AMP will serve to ensure there is not a loss of fracture toughness for the reactor shield wall structural steel. The Structures Monitoring (B.2.3.33) AMP manages loss of material for the accessible portions of the biological shield wall steel liners. The condition of the liners will be used to indicate the condition of the remaining biological shield wall steel. No additional aging management of the biological shield wall structural steel beyond the current Structures Monitoring (B.2.3.33) AMP is necessary for aging effects due to irradiation during the SPEO.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix Section A.2 of this SRP-SLR).

QA provisions applicable to License Renewal are discussed in Section B.1.3.

3.5.2.2.4 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix Section 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 time-limited aging analyses identified below are associated with the Containment, Structures and Component Supports:

- Section 4.6, Containment Liner Plate, Metal Containments, and Penetrations Fatigue
- Section 4.7.1, Fatigue of Cranes (Crane Cycle Limits)

3.5.3 CONCLUSION

The Containment, Structures and Component Supports that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Containment, Structures and Component Supports are identified in the summaries in Section 3.5.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Containment, Structures and Component Supports will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the SPEO.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 001	Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S2, “ASME Section XI, Subsection IWL” and/or AMP XI.S6, "Structure Monitoring"	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. A dewatering system was only relied upon during construction and is no longer being used. 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	AMP XI.S6, “Structures Monitoring”	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. A dewatering system was only relied upon during construction and is no longer being used. 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 aging management program or AMP XI.S2, “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.2)	Not applicable. 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 the Containments, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.5-1, 004	Steel elements (inaccessible areas): drywell shell; drywell head	Loss of material due to general, pitting, and crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of material of the inaccessible steel elements of the drywell shell and drywell head exposed to air - indoor uncontrolled and concrete environments. This item number is for BWR Mark III containments, but HNP finds this item number applicable for the aging effect and environment combination. 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, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE" and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Not applicable. This item number is not applicable to the HNP Mark I steel containment. Further evaluation is documented in Section 3.5.2.2.1.3.1.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 006	Steel elements: torus shell	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE" and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3.2)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of material of the steel elements of the torus shell exposed to air – indoor uncontrolled and treated water environments. Further evaluation is documented in Section 3.5.2.2.1.3.2.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 007	Steel elements: torus ring girders; downcomers; Steel elements: suppression chamber shell (interior surface)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, “ASME Section XI, Subsection IWE”	Yes (SRP-SLR Section 3.5.2.2.1.3.3)	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of material of the steel jet deflectors, torus shell, and ring girders in the primary containment exposed to air – indoor uncontrolled and treated water environments. The Structures Monitoring AMP (B.2.3.33) has been substituted for the ASME Section XI, Subsection IWE AMP (B.2.3.29) and is used to manage loss of material of structural steel (torus internal catwalk support columns, platforms, drywell interior platforms, stabilizers, radial beams seats, etc.) exposed to a treated water environment. Further evaluation is documented in Section 3.5.2.2.1.3.3.
3.5-1, 008	Prestressing system: tendons	Loss of prestress due to relaxation; shrinkage; creep; elevated temperature	TLAA, SRP-SLR Section 4.5, – "Concrete Containment Tendon Prestress" and/or SRP-SLR Section 4.7, " Other Plant-Specific Time-Limited Aging Analysis”	Yes (SRP-SLR Section 3.5.2.2.1.4)	Not applicable. This item number is not applicable to the HNP Mark I steel containment. This item number is applicable only to PWR and BWR prestressed concrete containments. Further evaluation is documented in Section 3.5.2.2.1.4.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 cyclic loading (Only if current licensing basis (CLB) fatigue analysis exists)	TLAA, SRP-SLR Section 4.6, “Containment Liner Plate and Penetration Fatigue Analysis"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Consistent with NUREG-2191. Fatigue is a TLAA for the downcomers, torus penetrations, torus shell, ECCS suction header, 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 RV to drywell refueling seal) components. This TLAA is evaluated in Section 4.6. Further evaluation is documented in Section 3.5.2.2.1.5.
3.5-1, 010	Penetration sleeves; penetration bellows	Cracking due to SCC	AMP XI.S1, “”ASME Section XI, Subsection IWE,”” and AMP XI.S4, “10 C”FR 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 AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage cracking of stainless steel and dissimilar metal welds for penetration assemblies and vent line bellows exposed to an air – indoor uncontrolled environment. Further evaluation is documented in Section 3.5.2.2.1.6.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 011	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific AMP or AMP XI.S2 “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.7)	Not applicable. This item number is not applicable to the HNP 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.
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 AMP XI.S2 “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.8)	Not applicable. This item number is not applicable to the HNP Mark I steel containment. The primary containment structure is completely enclosed and sheltered within the air-indoor environment of the reactor building. Further evaluation is documented in Section 3.5.2.2.1.8.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 AMP XI.S2 “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.9)	Not applicable. This item number is not applicable to the HNP Mark I steel containment. The concrete (inaccessible areas) components in primary containment are not exposed to a water - flowing environment. Further evaluation is documented in Section 3.5.2.2.1.9.
3.5-1, 016	Concrete (accessible areas): basemat, concrete: containment; wall	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S2, “ASME Section XI, Subsection IWL,” or AMP XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment which is supported on steel members which in turn is supported by the reactor building foundation.
3.5-1, 018	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S2, “ASME Section XI, Subsection IWL,” or AMP XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment which is supported on steel members which in turn is supported by the reactor building foundation.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 019	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment; concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	AMP XI.S2, "ASME Section XI, Section IWL," and/or AMPXI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment because there is no dome, wall, basemat, or concrete fill-in annulus for primary containment.
3.5-1, 020	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S2, “ASME Section XI, Subsection IWL”	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment. The concrete (accessible areas) components in primary containment are not exposed to a water - flowing environment.
3.5-1, 021	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S2, "ASME Section XI, Subsection IWL" and/or AMP XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment, which is supported on steel supporting members. These types of concrete components do not exist at HNP for the primary containment.
3.5-1, 023	Concrete (inaccessible areas): basemat; reinforcing steel, dome; wall	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S2, “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment. The primary containment internal concrete elements are classified as Group 4 Structures.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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	AMP XI.S2, “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment. This item number is applicable only to PWR and BWR Mark III containments.
3.5-1, 026	Moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S1, “ASME Section XI, Subsection IWE”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of sealing of the moisture barrier in the primary containment structure exposed to an air – indoor uncontrolled environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 027	Metal liner, metal plate, airlock, equipment hatch, CRD hatch; penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage cracking of stainless steel and dissimilar metal welds high-temperature piping drywell penetration assemblies (adapters, bellows, guard pipes, sleeves) and penetration assemblies - electrical, and steel penetration assemblies (containment spares, access manholes, inspection ports), personnel airlock, equipment hatch, suppression chamber manhole entrances, CRD hatch, seismic restraint inspection ports, including locks, hinges, and closure mechanisms due to cyclic loading exposed to an air – indoor uncontrolled environment. Further evaluation is documented in Section 3.5.2.2.1.5.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 028	Personnel airlock, equipment hatch, CRD hatch	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of material of the steel personnel airlock, equipment hatch, suppression chamber manhole entrances, CRD hatch, seismic restraint inspection ports, including locks, hinges, and closure mechanisms exposed to an air - indoor uncontrolled environment.
3.5-1, 029	Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms	Loss of leak tightness due to mechanical wear	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of leak tightness of the steel personnel airlock, equipment hatch, suppression chamber manhole entrances, CRD hatch, seismic restraint inspection ports, including locks, hinges, and closure mechanisms exposed to an air – indoor uncontrolled environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 030	Pressure retaining bolting	Loss of preload due to self-loosening	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of preload of steel bolting (containment closure) exposed to an air – indoor uncontrolled environment.
3.5-1, 031	Pressure retaining bolting, steel elements: downcomer pipes	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of material of steel bolting (containment closure) exposed to an air – indoor uncontrolled environment and downcomers exposed to an air – indoor uncontrolled and treated water environment.
3.5-1, 032	Prestressing system: tendons; anchorage components	Loss of material due to corrosion	AMP XI.S2, "ASME Section XI, Subsection IWL"	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment. This item number is applicable only to PWR and BWR prestressed concrete containments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 033	Seals and gaskets	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) is used to manage loss of sealing of the elastomer seals and gaskets in the primary containment exposed to an air – indoor uncontrolled environment.
3.5-1, 034	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Consistent with NUREG-2191. The Protective Coatings Monitoring and Maintenance AMP (B.2.3.35) is used to manage loss of coating or lining integrity of the Service Level I coatings in the primary containment exposed to air – indoor uncontrolled and treated water environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) program is used to manage loss of material of steel drywell shell, drywell head, drywell shell in sand pocket regions (accessible); and stainless steel and dissimilar metal welds penetration assemblies (electrical, mechanical guard pipe, mechanical sleeves) exposed to an air – indoor uncontrolled environment. Also used to manage loss of material of steel reactor well seal bulkhead plate exposed to air – indoor uncontrolled and treated water environments. Further evaluation is documented in Section 3.5.2.2.1.3.1.
3.5-1, 036	Steel elements: drywell head; downcomers	Loss of material due to mechanical wear, including fretting	AMP XI.S1, "ASME Section XI, Subsection IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage loss of material of the steel downcomers exposed to an air - indoor uncontrolled environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 037	Steel elements: suppression chamber (torus) liner (interior surface)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.S1, “ASME Section XI, Subsection IWE,“ and AMP XI.S4, “10 CFR Part 50, Appendix J"	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment. This item number is applicable only to concrete containments.
3.5-1, 038	Steel elements: suppression chamber shell (interior surface)	Cracking due to SCC	AMP XI.S1, “ASME Section XI, Subsection IWE,” and AMP XI.S4, “10 CFR Part 50, Appendix J”	Yes (SRP-SLR Section 3.5.2.2.1.6)	Not applicable. This item number is not applicable to the HNP 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 the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 039	Steel elements: vent line bellows	Cracking due to SCC	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.6)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) is used to manage cracking of the stainless steel vent line bellows exposed to an air – indoor uncontrolled environment. The Structures Monitoring AMP (B.2.3.33) has been substituted for the 10 CFR Part 50, Appendix J AMP (B.2.3.31) and ASME Section XI, Subsection IWE AMP (B.2.3.29) and is used to manage cracking of the stainless steel refueling water seal assembly (including reactor bellows support skirt, reactor well seal bulkhead plate) in the primary containment exposed to an air – indoor uncontrolled environment. Further evaluation is documented in Section 3.5.2.2.1.6.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 040	Unbraced downcomers, steel elements: vent header; downcomers	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, "ASME Section XI, Subsection IWE"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Not applicable. This item number is not applicable to the HNP 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.
3.5-1, 041	Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt	None	None	No	Not applicable. This item number is not applicable to the HNP Mark I steel containment. The drywell support skirt does not have an intended function and is not included in the scope of license renewal.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 042	Groups 1-3, 5, 7-9:concrete (inaccessible areas): foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.1)	Consistent with NUREG-2191 with exception. HNP is located in a moderate weathering region with concrete, for groups 1-3, and 8-9 structures. The Structures Monitoring AMP (B.2.3.33) will detect loss of material and cracking of accessible concrete due to freeze thaw in an air – outdoor or groundwater/soil environments, should it occur, and includes opportunistic examination of normally inaccessible components when excavated for other reasons. There are no concrete Groups 5 and 7 components applicable to HNP. Further evaluation is documented in Section 3.5.2.2.2.1.1.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.2)	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage cracking due to reaction with aggregates (such as ASR) in air – indoor uncontrolled, air – outdoor, and groundwater/soil environments for HNP groups 1-4, and 8-9 structures, including inaccessible areas. There are no concrete Groups 5 and 7 components applicable to HNP. Consistent with the current renewed licenses, a plant-specific AMP is not required to manage cracking in inaccessible areas. Further evaluation is documented in Section 3.5.2.2.2.1.2.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 044	All Groups: concrete: all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1.3)	Consistent with NUREG-2191 with exception. HNP does not rely on a dewatering system; thus, the Structures Monitoring AMP (B.2.3.33) is used to manage cracking and distortion of all the Group reinforced concrete elements of the HNP structures founded on soil and/or exposed to a groundwater/soil environment. There are no concrete Groups 5 and 7 components applicable to HNP. There are no concrete Group 4 components exposed to a soil environment. Further evaluation is documented in Section 3.5.2.2.2.1.3.
3.5-1, 046	Groups 1-3, 5-9: concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1.3)	Not applicable. As described for item number 3.5-1, 044 above, HNP does not rely upon a de-watering system to control settlement. In addition, structures are not founded on porous concrete foundations, subfoundations. Further evaluation is documented in Section 3.5.2.2.2.1.3.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.5-1, 047	Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring" enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.4)	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage increase in porosity and permeability, loss of strength of the reinforced concrete exposed to a water - flowing environment in Groups 1-3, 8, and 9 structures. This AMP includes opportunistic inspection of inaccessible concrete surfaces, when exposed because of excavation or modification, and will include evaluation of impact to inaccessible areas if leaching of calcium hydroxide or carbonation is observed in accessible areas. There are no concrete Groups 4, 5, and 7 components exposed to a water - flowing environment applicable to HNP. Further evaluation is documented in Section 3.5.2.2.2.1.4.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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" enhanced as necessary	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 HNP. There are no concrete structures exposed to elevated temperature (>150°F general; >200°F local). Further evaluation is documented in Section 3.5.2.2.2.2.
3.5-1, 049	Groups 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring" enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.1)	Consistent with NUREG-2191 with exception. HNP is located in a moderate weathering region with concrete for a group 6 structure. The Structures Monitoring AMP (B.2.3.33) will detect loss of material and cracking of accessible concrete due to freeze thaw exposed to air – outdoor or groundwater/soil environments, should it occur, and includes opportunistic examination of normally inaccessible components when excavated for other reasons. Further evaluation is documented in Section 3.5.2.2.2.3.1.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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" enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.2)	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) (which includes opportunistic inspection of inaccessible concrete when excavated for other reasons) is used to manage cracking in inaccessible areas of the HNP intake structure exposed to a groundwater/soil environment. Further evaluation is documented in Section 3.5.2.2.2.3.2.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.5-1, 051	Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring" enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.3)	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage increase in porosity and permeability, loss of strength of the reinforced concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab exposed to a water - flowing environment in the HNP Intake Structure. This AMP includes opportunistic inspection of inaccessible concrete surfaces, when excavated for other reasons, and will include evaluation of impact to inaccessible areas if leaching of calcium hydroxide or carbonation is observed in accessible areas. Further evaluation is documented in Section 3.5.2.2.2.3.3.
3.5-1, 052	Groups 7, 8 - steel components: tank liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.5.2.2.2.4)	Not applicable. HNP does not have Group 7 and 8 stainless steel tank liners exposed to standing water. Further evaluation is documented in Section 3.5.2.2.2.4

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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. Fatigue analysis for cranes and lifting devices components are addressed by item numbers 3.3-1, 001, 3.3-1, 052, and 3.3-1, 199. Fatigue analysis for Containment components are addressed by item number 3.5-1, 009. Further evaluation is documented in Section 3.5.2.2.2.5.
3.5-1, 054	All groups except 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage cracking of accessible concrete exposed to air – indoor uncontrolled and air – outdoor environments except for Group 6 structures.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 055	Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage reduction in concrete anchor capacity for joint and penetrations seals, building concrete at locations of expansion and grouted anchors, and grout pads for support base plates exposed to air – indoor uncontrolled and air – outdoor environments.
3.5-1, 056	Concrete: exterior above- and below-grade; foundation; interior slab	Loss of material due to abrasion; cavitation	AMP XI.S7, “Regulatory Guide 1.127, 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 AMP (B.2.3.34) is used to manage loss of material of accessible concrete exposed to a water – flowing environment in the HNP intake structure.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 057	Constant and variable load spring hangers; guides; stops	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP (B.2.3.30) is used to manage loss of mechanical function for steel ASME Class 1 piping supports, and ASME Class 2 and 3 piping and duct supports exposed to an air – indoor uncontrolled environment.
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. There are no earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds components in-scope at HNP.
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 AMP (B.2.3.34) is used to manage cracking, loss of bond, and loss of material of accessible concrete exposed to air- indoor uncontrolled, air – outdoor, and water – flowing environments in the HNP intake structure.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 060	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP (B.2.3.34) is used to manage cracking and loss of material of accessible concrete exposed to air- indoor uncontrolled, air – outdoor, and water – flowing environments in the HNP intake structure.
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 AMP (B.2.3.34) is used to manage increase in porosity and permeability and loss of strength of accessible concrete exposed to air- indoor uncontrolled, air – outdoor, and water – flowing environments in the HNP intake structure.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 components in-scope at HNP.
3.5-1, 063	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage increase in porosity and permeability and loss of strength of the reinforced concrete exposed to water- flowing in Groups 1-3, 8, and 9 structures. There are no concrete Groups 5 and 7 components applicable to HNP.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage cracking and loss of material of the reinforced concrete exposed to air – outdoor in Groups 1-3, 8, and 9 structures. There are no concrete Groups 5 and 7 components applicable to HNP.
3.5-1, 065	Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Groups 6: concrete (inaccessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage cracking, loss of bond, and loss of material of the reinforced concrete exposed to a groundwater/soil environment in Groups 1-3 8, and 9 structures, and of reinforced inaccessible concrete exposed to air – indoor uncontrolled, air – outdoor, and groundwater/soil environments in the Group 6 structure. The Structures Monitoring AMP (B.2.3.33) is used to manage cracking of the reactor shield wall reinforced inaccessible concrete exposed to an air - indoor uncontrolled environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 066	Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage cracking, loss of bond, and loss of material of the reinforced concrete exposed to air - indoor uncontrolled and air - outdoor environments in Groups 1-4, 8, and 9 structures. There are no concrete Groups 5 and 7 components applicable to HNP.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 067	Groups 1-5, 7, 9: Concrete: interior; above-grade exterior, Groups 1-3, 5, 7-9 - concrete (inaccessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage increase in porosity and permeability, cracking, and loss of material of the interior, above-grade exterior reinforced concrete exposed to air – indoor uncontrolled and air – outdoor environments in Groups 1-3 and 9 structures, below grade exterior, foundation reinforced inaccessible concrete exposed to groundwater/soil environments in Groups 1-3, 8, and 9 structures, and the reinforced inaccessible concrete exposed to air – outdoor and groundwater/soil environments in the Group 6 structure. There are no concrete Groups 5 and 7 components applicable to HNP. The concrete components inside of the drywell evaluated as part of a Group 4 structure are not susceptible to increase in porosity and permeability. Cracking and loss of material are addressed in item numbers 3.5-1, 043, 3.5-1, 054, and 3.5-1, 066.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 068	High-strength structural bolting	Cracking due to SCC	AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP (B.2.3.30) is used to manage cracking of high-strength steel bolting exposed to air – indoor uncontrolled and treated water environments.
3.5-1, 070	Masonry walls: all	Cracking due to restraint shrinkage, creep, and aggressive environment	AMP XI.S5, “Masonry Walls”	No	Consistent with NUREG-2191. The Masonry Wall AMP (B.2.3.32) is used to manage cracking of masonry walls exposed to an air – indoor uncontrolled environment.
3.5-1, 071	Masonry walls: all	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S5, “Masonry Walls"	No	Not applicable. There is no masonry walls exposed to an air – outdoor environment in-scope at HNP.
3.5-1, 072	Seals; gasket; moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of sealing for three-bulb water stop, and joint and penetration seals exposed to air – indoor uncontrolled and air – outdoor environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.5-1, 073	Service Level I coatings	Loss of coating integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Not applicable Service Level 1 coatings inside primary containment are addressed in item number 3.5-1, 034. There are no Service Level 1 coatings outside primary containment.
3.5-1, 074	Sliding support bearings; sliding support surfaces	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of mechanical function for sliding surfaces (drywell interior platform sliding plates) exposed to an air – indoor uncontrolled environment.
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	Not applicable. Applicable sliding components addressed under item number 3.5-1, 074. There are no ASME sliding surfaces exposed to air – indoor uncontrolled outside of primary containment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 076	Sliding surfaces: radial beam seats in BWR drywell	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, “Structures Monitoring"	No	Not applicable. Applicable sliding components addressed under item number 3.5-1, 074. There are no Lubrite or similar sliding surfaces for BWR radial beam seats exposed to air – indoor uncontrolled in the HNP drywell.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 077	Steel components: all structural steel	Loss of material due to corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of material of airlock (MCR), ballistic shield, concrete elements: embedments, doors, fuel preparation machine framing, louver, miscellaneous steel (stairs, ladders, handrails, etc.), pit boxes, railroad airlock, reactor shield wall (columns, beams, liner, doors), refueling water seal assembly (including reactor bellows support skirt, reactor well seal bulkhead plate), RV pedestal, structural steel, structural steel (torus internal catwalk support columns, platforms, drywell interior platforms, stabilizers, radial beam seats, etc.), transmission tower, and water spray shield exposed to air – indoor uncontrolled and air – outdoor environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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 in accordance with technical specifications and leakage from the leak chase channels.	No	Consistent with NUREG-2191 with exception. The Water Chemistry AMP (B.2.3.2) 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 a treated water environment.
3.5-1, 079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of material of Non-ASME Class supports, steel frame pull boxes, and steel piles exposed to a groundwater/soil environment.
3.5-1, 080	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of material for steel structural bolting exposed to uncontrolled air – indoor uncontrolled and air – outdoor environments in Containment and Plant structures.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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 AMP (B.2.3.30) is used to manage loss of material for ASME Class 1, ASME Class 2, ASME Class 3, ASME Class MC steel structural bolting exposed to air – indoor uncontrolled environment in the component supports and structural commodity group.
3.5-1, 082	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of material for steel structural bolting exposed to an air – outdoor environment in Plant structures.
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 AMP (B.2.3.34) is used to manage loss of material for steel stop logs, structural bolting, trash racks, and traveling screens exposed to air – indoor uncontrolled, air – outdoor, and water – flowing or standing environments in the HNP intake structure.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 085	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.M2, “Water Chemistry,” for BWR water, and Chapter XI.S3, “ASME Section XI, Subsection IWF”	No	Not applicable. Stainless steel bolting exposed to a treated water environment is addressed in item number 3.3-1, 125.
3.5-1, 086	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF AMP (B.2.3.30) is used to manage loss of material for ASME Class 1, ASME Class 2, ASME Class 3, and ASME Class MC steel structural bolting in an air – outdoor environment.
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 AMP (B.2.3.30) is used to manage loss of preload for ASME Class 1, ASME Class 2, ASME Class 3, and ASME Class MC steel structural bolting in an air-indoor uncontrolled environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of preload for steel structural bolting exposed to air – indoor uncontrolled, air – outdoor, treated water, and water - flowing or standing environments.
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. Boric acid corrosion is not applicable for HNP.
3.5-1, 090	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, “Water Chemistry,” and AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191 with exception for the Water Chemistry AMP (B.2.3.2). The Water Chemistry AMP (B.2.3.2) and ASME Section XI, Subsection IWF AMP (B.2.3.30) are used to manage loss of material for non-ASME Class supports (spent fuel pool) exposed to a treated water environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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 AMP (B.2.3.30) is used to manage loss of material for steel ASME Class 1 piping supports, ASME Class 2 and 3 piping and ducts supports, and ASME Class MC piping supports exposed to an air – indoor uncontrolled environment.
3.5-1, 092	welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of material for anchorage / embedment, bird screen, cabinet, panel, rack, other enclosures, cable tray, non-ASME Class supports, penetration sleeves, pipe restraint, and miscellaneous steel (stairs, ladders, handrails, etc.) exposed to air – indoor uncontrolled and air – outdoor 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	Consistent with NUREG-2191 with exception. The Structures Monitoring AMP (B.2.3.33) is used to manage loss of material for steel cable trays exposed to an air – outdoor environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 094	Vibration isolation elements	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	AMP XI.S3, "ASME Section XI, Subsection IWF," and/or AMP XI.S6, "Structures Monitoring"	No	Not applicable. There is no vibration isolation elements in-scope at HNP.
3.5-1, 095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not applicable. Galvanized steel support members; welds; bolted connections; support anchorage to building structure are credited to item number 3.5-1, 092.
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 AMP (B.2.3.34) is used to manage cracking for accessible concrete at the HNP intake structure exposed to air – indoor uncontrolled, air – outdoor, and water - flowing environments.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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. The Structures Monitoring AMP (B.2.3.33) is used to manage reduction of strength and loss of mechanical properties of the reinforced concrete interior (drywell equipment foundations) and reactor shield wall exposed to an air – indoor uncontrolled environment. 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 applicable. This item number is not applicable to HNP. There are no stainless steel or aluminum alloy support members; welds; bolted connections; support anchorage to building structure exposed to an air with borated water leakage environment.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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 with exception for the Structures Monitoring (B.2.3.33). The ASME Section XI, Subsection IWF AMP (B.2.3.30) is used to manage cracking and loss of material for stainless steel ASME Class 1 piping supports, and ASME Class 2 and 3 piping and ducts supports in plant structures exposed to an air – indoor uncontrolled environment. The Structures Monitoring (B.2.3.33) program has been substituted for the One-Time Inspection (B.2.3.20) and is used to manage loss of material of the stainless steel support members, welds, bolted connections, support anchorage to building structure in primary containment exposed to an air – indoor uncontrolled environment. Further evaluation is documented in Section 3.5.2.2.2.4.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 100	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion, cracking due to SCC	AMP XI.M32, “One-Time Inspection,” AMP XI.S6, “Structures Monitoring,” or AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191 with exception for the Structures Monitoring AMP (B.2.3.33). The Structures Monitoring AMP (B.2.3.33) is used to manage loss of material and cracking of aluminum blowout panels, new fuel storage racks, pull boxes cover plates, cable trays, and fire doors (molding, accessories), and stainless steel fire doors (hinges) exposed to air – indoor uncontrolled and air – outdoor environments. The External Surfaces Monitoring of Mechanical Components AMP (B.2.3.23) is used to manage loss of material and cracking of aluminum and stainless steel jacketing exposed to air – indoor uncontrolled and air – outdoor environments. Further evaluation is documented in Section 3.5.2.2.2.4.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 101	Wooden Poles	Loss of material; changes in material properties due to weathering, chemical degradation, insect infestation, repeated wetting and drying, fungal decay	Plant-specific aging management program, or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.7)	Not applicable. There are no wooden poles in-scope at HNP. Further evaluation is documented in Section 3.5.2.2.2.7.
3.5-1, 102	Reactor vessel steel structural supports, their assembled components (e.g., reactor vessel steel support skirt assembly; reactor vessel support girders/columns structure; neutron shield tank; reactor vessel support sliding feet assembly; reactor vessel seismic restraints; welds; bolted connections; support anchorage to building structure)	Reduction in fracture toughness and/or loss of intended function (mechanical/ structural) due to irradiation-induced combined mechanisms	Plant-specific aging management program, or plant-specific enhancements to selected GALL-SLR AMPs (e.g., AMP XI.S3, “ASME Section XI, Subsection IWF,” and/or AMP XI.S6, “Structures Monitoring”)	Yes (SRP-SLR Section 3.5.2.2.2.8)	Consistent with NUREG-2191. Further evaluation is documented in Section 3.5.2.2.2.8.

Table 3.5-1: Summary of Aging Management Evaluations for the Containments, Structures, and Component Supports					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 103	Reactor vessel support sliding surfaces, other special components (e.g., special coatings)	Loss of intended function (mechanical) due to irradiation	Plant-specific aging management program or plant-specific enhancement to selected GALL-SLR AMPs	Yes (SRP-SLR Section 3.5.2.2.2.8)	Not applicable. HNP does not have any sliding surfaces associated with the RV support or other special components that would be subject to loss of intended function (mechanical) due to irradiation. Further evaluation is documented in Section 3.5.2.2.2.8.

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
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	A
Bolting (Containment closure)	Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of preload	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-150	3.5-1, 030	A
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	B
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	B
Concrete elements: anchors	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A4.TP-248	3.5-1, 080	B
Concrete elements: anchors	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.33)	III.A4.TP-261	3.5-1, 088	B
Concrete elements: embedments	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A4.TP-302	3.5-1, 077	B
Concrete: Interior (drywell equipment foundations)	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	B
Concrete: Interior (drywell equipment foundations) (accessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A4.TP-25	3.5-1, 054	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**
Concrete: Interior (drywell equipment foundations) (accessible)	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	B
Concrete: Interior (drywell equipment foundations) (inaccessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A4.TP-204	3.5-1, 043	B
Concrete: Interior (drywell equipment foundations) (inaccessible)	Structural support	Concrete (reinforced)	Air – indoor uncontrolled	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-104	3.5-1, 065	B
Downcomers	Direct flow Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, Containment Liner Plate and Penetration Fatigue Analysis	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	A
Downcomers	Direct flow Pressure boundary Structural support	Steel	Air – indoor uncontrolled Treated water	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29)	II.B1.2.CP-117	3.5-1, 031	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**
Drywell shell, drywell head, drywell shell in sand pocket regions (accessible)	HELB shielding Missile barrier Pressure boundary Shelter, protection Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B1.1.CP-43	3.5-1, 035	A
Drywell shell, drywell head, drywell shell in sand pocket regions (inaccessible)	HELB shielding 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) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B3.1.CP-113	3.5-1, 004	A, 1
High-strength bolting	Structural support	Steel	Air – indoor uncontrolled Treated water	Cracking	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-41	3.5-1, 068	A
High-strength bolting	Structural support	Steel	Air – indoor uncontrolled Treated water	Loss of preload	Structures Monitoring (B.2.3.33)	III.A4.TP-261	3.5-1, 088	B
Jet deflectors	Shelter, protection HELB shielding	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	A
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	A
Penetration assemblies - containment spares, access manholes, inspection ports	Shelter, protection Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-37	3.5-1, 027	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**
Penetration assemblies - containment spares, access manholes, inspection ports	Shelter, protection Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29)	II.B4.CP-37	3.5-1, 027	A
Penetration assemblies - electrical	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-38	3.5-1, 010	A
Penetration assemblies - electrical	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.A3.CP-37	3.5-1, 027	A
Penetration assemblies - electrical	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-36	3.5-1, 035	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
Penetration assemblies - mechanical (bellows)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-38	3.5-1, 010	A
Penetration assemblies - mechanical (bellows)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.A3.CP-37	3.5-1, 027	A
Penetration assemblies - mechanical (guard pipe)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.A3.CP-37	3.5-1, 027	A
Penetration assemblies - mechanical (guard pipe)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-36	3.5-1, 035	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
Penetration assemblies - mechanical (sleeves)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.A3.CP-37	3.5-1, 027	A
Penetration assemblies - mechanical (sleeves)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-36	3.5-1, 035	A
Penetration assemblies - mechanical piping (adapters)	Flood barrier HELB shielding Pressure boundary Shelter, protection Structural support	Stainless steel dissimilar metal welds	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-37	3.5-1, 027	A, 2

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
Personnel airlock, equipment hatch, suppression chamber manhole entrances, CRD hatch, seismic restraint inspection ports, including locks, hinges, and closure mechanisms	Flood barrier HELB shielding Missile barrier Pressure boundary	Steel	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.A3.CP-37	3.5-1, 027	A
Personnel airlock, equipment hatch, suppression chamber manhole entrances, CRD hatch, seismic restraint inspection ports, including locks, hinges, and closure mechanisms	Flood barrier HELB shielding Missile barrier Pressure boundary	Steel	Air – indoor uncontrolled	Loss of leak tightness	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-39	3.5-1, 029	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
Personnel airlock, equipment hatch, suppression chamber manhole entrances, CRD hatch, seismic restraint inspection ports, including locks, hinges, and closure mechanisms	Flood barrier HELB shielding Missile barrier Pressure boundary	Steel	Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.C-16	3.5-1, 028	A
Reactor 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	D
Reactor shield wall (inaccessible)	Radiation shielding	Concrete (unreinforced)	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A4.TP-204	3.5-1, 043	B
Reactor well seal bulkhead plate	Pressure boundary	Steel	Air – indoor uncontrolled Treated water	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.A1.CP-35	3.5-1, 035	A
Refueling water seal assembly (including reactor bellows support skirt, reactor well seal bulkhead plate)	Structural support Water retaining boundary	Stainless steel	Air – indoor uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	II.B1.1.CP-50	3.5-1, 039	E, 3

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**
Refueling water seal assembly (including reactor bellows support skirt, reactor well seal bulkhead plate)	Structural support Water retaining boundary	Stainless steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, Containment Liner Plate and Penetration Fatigue Analysis	II.B1.1.C-21	3.5-1, 009	C
Refueling water seal assembly (including reactor bellows support skirt, reactor well seal bulkhead plate)	Structural support Water retaining boundary	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A4.TP-302	3.5-1, 077	B
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	B
Seals and gaskets	HELB shielding 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
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	Structures Monitoring (B.2.3.33)	III.B2.TP-46	3.5-1, 074	B
Structural steel	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A4.TP-302	3.5-1, 077	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
Structural steel (torus internal catwalk support columns, platforms, 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	B
Structural steel (torus internal catwalk support columns, platforms, drywell interior platforms, stabilizers, radial beam seats, etc.)	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
Support members, welds, bolted connections, support anchorage to building structure	Structural support	Stainless steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.B1.1.T-36a	3.5-1, 099	E, 5
Torus shell	Flood barrier Heat sink HELB shielding Missile barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled Treated water	Cumulative fatigue damage	TLAA - Section 4.6, Containment Liner Plate and Penetration Fatigue Analysis	II.B2.2.C-48	3.5-1, 009	C

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	Flood barrier Heat sink HELB shielding Missile barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled Treated water	Loss of material	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B1.1.CP-48	3.5-1, 006	A
Torus shell, ring girders	Flood barrier Heat sink HELB shielding 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	A
Torus vent lines, vent header	Flood barrier Heat sink HELB shielding Missile barrier Pressure boundary Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, Containment Liner Plate and Penetration Fatigue Analysis	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) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-38	3.5-1, 010	A
Vent line bellows	Flood barrier Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) 10 CFR Part 50, Appendix J (B.2.3.31)	II.B1.1.CP-50	3.5-1, 039	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**
Vent line bellows	Flood barrier Pressure boundary Structural support	Stainless steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.6, Containment Liner Plate and Penetration Fatigue Analysis	II.B1.1.C-21	3.5-1, 009	A
Vent line jet deflectors	Shelter, protection HELB shielding	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	A

General Notes

A. Consistent with component, material, environment, aging effect and aging management program 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 aging management program 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. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item associated with Mark III containments. HNP is a Mark I containment.
2. High-temperature piping penetrations, such as for main steam and feedwater, are considered susceptible to cyclic loading.
3. The refueling water seal assembly 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. Stainless steel support members in an air-indoor environment will be managed by the Structural Monitoring (B.2.3.33) AMP instead of the One-Time Inspection (B.2.3.20) AMP.

Table 3.5.2-2: Component Supports and Structural 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	B
Anchorage / embedment	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	B
Anchorage / embedment	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B3.TP-248	3.5-1, 080	B
ASME Class 1 piping supports	Structural support	Stainless steel	Air – indoor uncontrolled	Cracking 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 piping 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 piping 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 1 structural bolting	Structural support	Steel	Air – outdoor	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-235	3.5-1, 086	A
ASME Class 1 supports	Structural support	Steel	Air – indoor uncontrolled	Loss of fracture toughness Loss of intended function	ASME Section XI, Subsection IWF (B.2.3.30)	III.A4.T-36	3.5-1, 102	A
ASME Class 2 and 3 piping and ducts supports	Structural support	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.T-36b	3.5-1, 099	A

Table 3.5.2-2: Component Supports and Structural 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 piping and ducts 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 piping and ducts 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 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
ASME Class 2 and 3 structural bolting	Structural support	Steel	Air – outdoor	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.TP-235	3.5-1, 086	A
ASME Class MC piping 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
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.T-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.T-229	3.5-1, 087	A
ASME Class MC structural bolting	Structural support	Steel	Air – outdoor	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.3.T-235	3.5-1, 086	A
Bird screen	Shelter, protection	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B2.TP-43	3.5-1, 092	D

Table 3.5.2-2: Component Supports and Structural 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**
Cabinet, panel, rack, and other enclosure	Shelter, protection Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.B2.TP-43	3.5-1, 092	B
Cable tray	Shelter, protection Structural support	Aluminum	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5-1, 100	B
Cable tray	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	B
Cable tray	Shelter, protection Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B2.TP-6	3.5-1, 093	B
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	B
High-strength bolting	Structural support	Steel	Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-41	3.5-1, 068	A
High-strength bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B.2.3.33)	III.A4.TP-261	3.5-1, 088	B
Insulation	Insulate (thermal)	Asbestos	Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-704	3.3-1, 182	A
Insulation	Insulate (thermal)	Calcium silicate	Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-704	3.3-1, 182	A
Insulation	Insulate (thermal)	Ceramic	Air – indoor uncontrolled Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-704	3.3-1, 182	A

Table 3.5.2-2: Component Supports and Structural 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	Insulate (thermal)	Fiberglass	Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-704	3.3-1, 182	A
Insulation	Insulate (thermal)	Kaowool	Air – indoor uncontrolled Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-704	3.3-1, 182	A
Jacketing	Thermal insulation jacket integrity	Aluminum	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
Jacketing	Thermal 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
Joint and penetration seals	Flood barrier HELB barrier Pressure boundary Shelter, protection Shielding	Elastomer	Air – indoor uncontrolled Air – outdoor	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B
Joint and penetration seals	Flood barrier HELB barrier Pressure boundary Shelter, protection Shielding	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	B
Non-ASME Class 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	B
Non-ASME Class supports	Structural support	Steel	Groundwater/soil	Loss of material	Structures Monitoring (B.2.3.33)	III.A2.TP-219	3.5-1, 079	D

Table 3.5.2-2: Component Supports and Structural 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**
Non-ASME Class supports (spent fuel pool)	Structural support	Steel	Treated water	Loss of material	ASME Section XI, Subsection IWF (B.2.3.30) Water Chemistry (B.2.3.2)	III.B1.1.TP-10	3.5-1, 090	A B
Penetration sleeves	Flood barrier HELB barrier Shelter, protection Shielding	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.B3.TP-43	3.5-1, 092	B
Pipe restraint	HELB barrier Pipe whip restraint Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.B3.TP-43	3.5-1, 092	B
Reflective metal insulation	Insulate (thermal)	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
Reflective metal insulation	Insulate (thermal)	Aluminum	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
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	B
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	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	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 3.5.2-3: Concrete 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	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support	Concrete; 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	B
Concrete (accessible areas): all	Direct flow 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.A1.TP-25 III.A2.TP-25 III.A3.TP-25 III.A8.TP-25 III.A9.TP-25	3.5-1, 054	B
Concrete (accessible areas): all	Flood barrier HELB 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.T-34	3.5-1, 096	A

Table 3.5.2-3: Concrete 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 (accessible areas): all	Flood barrier HELB 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
Concrete (accessible areas): below-grade exterior, foundation	Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-27 III.A2.TP-27 III.A3.TP-27 III.A8.TP-27 III.A9.TP-27	3.5-1, 065	B
Concrete (accessible areas): exterior above- and below-grade, foundation	Flood 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
Concrete (accessible areas): exterior above- and below-grade, foundation	Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-23 III.A2.TP-23 III.A3.TP-23 III.A8.TP-23 III.A9.TP-23	3.5-1, 064	B
Concrete (accessible areas): exterior above- and below-grade, foundation	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.A1.TP-24 III.A2.TP-24 III.A3.TP-24 III.A8.TP-24 III.A9.TP-24	3.5-1, 063	B

Table 3.5.2-3: Concrete 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 (accessible areas): exterior above- and below-grade, foundation, interior slab	Flood barrier HELB 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
Concrete (accessible areas): interior and above-grade exterior	Direct flow 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.A1.TP-26 III.A2.TP-26 III.A3.TP-26 III.A9.TP-26	3.5-1, 066	B
Concrete (inaccessible areas): all	Flood barrier HELB barrier Missile barrier Pressure boundary Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A1.TP-204 III.A2.TP-204 III.A3.TP-204 III.A8.TP-204 III.A9.TP-204	3.5-1, 043	B

Table 3.5.2-3: Concrete 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 (inaccessible areas): all	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – indoor uncontrolled Air – outdoor Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-104	3.5-1, 065	B
Concrete (inaccessible areas): all	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor 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	B
Concrete (inaccessible areas): all	Flood barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking	Structures Monitoring (B.2.3.33)	III.A6.TP-220	3.5-1, 050	B
Concrete (inaccessible areas): below-grade exterior, foundation	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.A1.TP-29 III.A2.TP-29 III.A3.TP-29 III.A8.TP-29 III.A9.TP-29	3.5-1, 067	B
Concrete (inaccessible areas): below-grade exterior, foundation	Flood barrier Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Loss of bond Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-212 III.A2.TP-212 III.A3.TP-212 III.A8.TP-212 III.A9.TP-212	3.5-1, 065	B

Table 3.5.2-3: Concrete 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 (inaccessible areas): exterior above- and below-grade, foundation	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.A1.TP-67 III.A2.TP-67 III.A3.TP-67 III.A8.TP-67 III.A9.TP-67	3.5-1, 047	B
Concrete (inaccessible areas): exterior above- and below-grade, foundation, interior slab	Flood barrier HELB 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	B
Concrete (inaccessible areas): exterior above- and below-grade, foundation, interior slab	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.A6.TP-109	3.5-1, 051	B
Concrete (inaccessible areas): foundation	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Air – outdoor Groundwater/soil	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-108 III.A2.TP-108 III.A3.TP-108 III.A8.TP-108 III.A9.TP-108	3.5-1, 042	B

Table 3.5.2-3: Concrete 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: all	Flood barrier HELB barrier Missile barrier Shelter, protection Structural support	Concrete (reinforced)	Groundwater/soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A1.TP-30 III.A2.TP-30 III.A3.TP-30 III.A6.TP-30 III.A8.TP-30 III.A9.TP-30	3.5-1, 044	B
Concrete: exterior above- and below-grade, foundation, interior slab	Direct flow Flood 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.T-20	3.5-1, 056	A
Concrete: interior, above-grade exterior	Direct flow 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.A1.TP-28 III.A2.TP-28 III.A3.TP-28 III.A9.TP-28	3.5-1, 067	B
Masonry walls	Shelter, protection Structural support	Concrete block	Air – indoor uncontrolled	Cracking	Masonry Walls (B.2.3.32)	III.A1.T-12 III.A2.T-12 III.A3.T-12	3.5-1, 070	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. Consistent with NUREG-2191 item for component, material, environment, and aging effect.

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 3.5.2-4: Control 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 (MCR)	Pressure boundary Shelter, protection	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Ballistic shield	Missile barrier	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Blowout panels	Pressure boundary Pressure relief Shelter, protection Structural support	Aluminum	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5-1, 100	D
Doors	Pressure boundary Shelter, protection	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Louver	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A1.TP-261	3.5-1, 088	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-274	3.5-1, 082	B
Structural steel	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B

General Notes

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.

Plant Specific Notes

None.

Table 3.5.2-5: Cranes, Heavy Loads, Rigging – Summary 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: bridges, structural members, structural components	Structural support	Steel	Air – indoor uncontrolled	Cumulative fatigue damage	TLAA - Section 4.7, Fatigue of Cranes (Crane Cycle Limits)	VII.B.A-06	3.3-1, 001	A
Cranes and lifting devices: rails, bridges, structural members, structural components	Structural support	Steel	Air – indoor uncontrolled	Cracking 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
Cranes and lifting devices: 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
Fuel preparation machine framing	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Refueling platform	Structural support	Steel	Air – indoor uncontrolled	Cracking 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

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 3.5.2-6: EDG 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	B
Louver	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
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	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
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	B
Structural Steel	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B

General Notes

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 3.5.2-7: Fire Barrier 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 fire barriers	Fire barrier	Steel	Air – indoor uncontrolled	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	C
Concrete: fire protection barrier	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 B
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 and vent 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 doors	Fire barrier	Steel	Air – indoor uncontrolled	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	A
Fire doors (hinges)	Fire barrier	Stainless steel	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5-1, 100	B
Fire doors (interior core)	Fire barrier	Gypsum	Air – indoor uncontrolled	None	Fire Protection (B.2.3.15)	None	None	J, 1
Fire doors (interior core)	Fire barrier	Polystyrene foam	Air – indoor uncontrolled	None	Fire Protection (B.2.3.15)	None	None	J, 1
Fire doors (interior core)	Fire barrier	Rockwool	Air – indoor uncontrolled	Change in material properties Cracking Delamination Loss of material Separation	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	C
Fire doors (interior core)	Fire barrier	Urethane foam	Air – indoor uncontrolled	None	Fire Protection (B.2.3.15)	None	None	J, 1
Fire doors (molding, accessories)	Fire barrier	Aluminum	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5-1, 100	B

Table 3.5.2-7: Fire Barrier 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
Fire doors (thrust bearings)	Fire barrier	Copper alloy	Air – indoor uncontrolled	None	None	V.F.EP-10	3.2-1, 057	C
Fireproofing	Fire barrier	Cementitious	Air – indoor uncontrolled	Change in material properties Cracking Delamination Loss of material	Fire Protection (B.2.3.15)	VII.G.A-806	3.3-1, 268	A
Fireproofing	Fire barrier	Silicate	Air – indoor uncontrolled	Change in material properties Cracking Delamination Loss of material	Fire Protection (B.2.3.15)	VII.G.A-807	3.3-1, 269	A
Fireproofing	Fire barrier	Subliming	Air – indoor uncontrolled	Change in material properties Cracking Delamination Loss of material	Fire Protection (B.2.3.15)	VII.G.A-805	3.3-1, 267	A
Kaowool hold-down straps and fasteners	Fire barrier Structural support	Steel	Air – indoor uncontrolled	Loss of material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3-1, 059	C
Masonry 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
Thermal fiber	Fire barrier	Silicate	Air – indoor uncontrolled	Change in material properties Cracking Delamination 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.

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.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes

1. The Fire Protection (B.2.3.15) AMP will confirm no aging effects for the interior cores of fire doors.

Table 3.5.2-8: Intake 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
Ballistic shield	Missile barrier	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
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	B
Louver	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Miscellaneous steel (stairs, ladders, handrails, etc.)	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	B
Stop logs	Shelter, protection	Steel	Air – outdoor Water - flowing or standing	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	C
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A6.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor Water - flowing or standing	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 Water - flowing or standing	Loss of preload	Structures Monitoring (B.2.3.33)	III.A6.TP-261	3.5-1, 088	B
Structural steel	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B

Table 3.5.2-8: Intake 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**
Trash racks	Filter	Steel	Air – outdoor Water - flowing or standing	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	C

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 3.5.2-9: Main 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
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	B
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Steel components: piles	Structural support	Steel	Groundwater/soil	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5-1, 079	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A9.TP-248	3.5-1, 080	B
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	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A9.TP-274	3.5-1, 082	B
Structural steel	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B

General Notes

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 3.5.2-10: Radwaste 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	B
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
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	B
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	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Structural steel	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	B

General Notes

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 3.5.2-11: 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
Ballistic shield	Missile barrier	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Blowout panels	Pressure relief Shelter, protection Structural support	Aluminum	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5-1, 100	D
Blowout panels	Pressure relief Shelter, protection Structural support	Polymeric	Air – indoor uncontrolled Air – outdoor	Blistering Cracking Hardening Loss of material Loss of strength	Structures Monitoring (B.2.3.33)	V.E.E-477a	3.2-1, 134	E, 1
Boral plate	Absorb neutrons	Boral	Treated water	Change in dimensions Loss of material Reduction of neutron-absorbing capacity	Monitoring of Neutron-Absorbing Material Other Than Boraflex (B.2.3.26)	VII.A2.AP-236	3.3-1, 102	A
Doors	Shelter, protection	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
New fuel storage racks	Structural support	Aluminum	Air – indoor uncontrolled	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5-1, 100	D

Table 3.5.2-11: 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
Railroad airlock	HELB barrier Missile barrier Pressure boundary Shelter, protection	Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Seismic restraints for spent fuel storage racks	Structural support	Aluminum	Treated water	Loss of material	One-Time Inspection (B.2.3.20) Water Chemistry (B.2.3.2)	VII.A4.AP-130	3.3-1, 025	C D
Spent fuel pool gate	Pressure boundary Structural support	Stainless steel	Treated water	Loss of material	One-Time Inspection (B.2.3.20) Water Chemistry (B.2.3.2)	VII.A2.A-98	3.3-1, 125	C D
Spent fuel pool 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
Spent fuel storage racks	Structural support	Stainless steel	Treated water	Loss of material	One-Time Inspection (B.2.3.20) Water Chemistry (B.2.3.2)	VII.A2.A-98	3.3-1, 125	A B
Structural bolting	Structural support	Stainless steel	Treated water	Loss of material	One-Time Inspection (B.2.3.20) Water Chemistry (B.2.3.2)	VII.A2.A-98	3.3-1, 125	C D
Structural bolting	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – indoor uncontrolled Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A1.TP-261	3.5-1, 088	B

Table 3.5.2-11: 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**
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-274	3.5-1, 082	B
Structural steel	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A1.TP-302	3.5-1, 077	B
Three-bulb water stop	Pressure boundary	Rubber	Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5-1, 072	B
Tornado vent frames	Structural support	Aluminum	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5-1, 100	D

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 Structures Monitoring (B.2.3.33) AMP will be used in place of External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP to manage the applicable aging effects for this material and environment combination.

Table 3.5.2-12: Switchyard 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
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	B
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
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	B
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	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Structural steel	Structural support	Steel	Air – indoor uncontrolled	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Transmission tower	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B

General Notes

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 3.5.2-13: 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**
Blowout panels	Pressure relief Shelter, protection Structural support	Aluminum	Air – indoor uncontrolled Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5-1, 100	D
Blowout panels	Pressure relief Shelter, protection Structural support	Polymeric	Air – indoor uncontrolled Air – outdoor	Blistering Cracking Hardening Loss of material Loss of strength	Structures Monitoring (B.2.3.33)	V.E.E-477a	3.2-1, 134	E, 1
Doors	HELB 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	B
Miscellaneous steel (stairs, ladders, handrails, etc.)	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	B
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	B
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	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Structural steel	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	B

General Notes

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. The Structures Monitoring (B.2.3.33) AMP will be used in place of External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP to manage the applicable aging effects for this material and environment combination.

Table 3.5.2-14: Yard Structures and Tank Foundations – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Cover plates: pull boxes	Flood barrier Shelter, protection	Aluminum	Air – outdoor	Cracking Loss of material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5-1, 100	D
Miscellaneous steel (stairs, ladders, handrails, etc.)	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302 III.A8.TP-302	3.5-1, 077	B
Pit boxes	Flood barrier Shelter, protection	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B
Steel frame: pull boxes	Structural support	Steel	Groundwater/soil	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5-1, 079	D
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5-1, 080	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5-1, 082	B
Structural bolting	Structural support	Steel	Air – outdoor	Loss of preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5-1, 088	B
Structural steel	Structural support	Steel	Air – outdoor	Loss of material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5-1, 077	B

General Notes

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.

Plant Specific Notes

None.

3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROLS

3.6.1 Introduction

This section provides the results of the 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:

- Cable bus
- Cable connections (metallic)
- Electrical insulation for:[1]
  - Electrical 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 instrumentation and control 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
- Fuse Holders (not part of active equipment)
- High-voltage electrical insulators
- Metal-Enclosed Bus
- Switchyard bus and connections
- Transmission conductors and connections

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.

[1] *This commodity group is subdivided for technical clarity and proper identification of applicable aging effects consistent with NUREG-2191 guidance.*

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 aging management programs for electrical commodities subject to aging management review. 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 and aluminum alloy
- Bronze
- Cement
- Copper
- Elastomer - various organic materials
- Galvanized metals
- Insulation material – various organic polymers
- Malleable iron
- Porcelain
- Polymer
- Silicone Rubber
- Stainless steel
- Steel
- Various metals used for bus and electrical connections

Environment

Electrical commodities subject to aging management review are exposed to the following environments:

- Adverse localized environment (ALE) caused by heat, radiation, contamination, or moisture
- ALE caused by significant moisture
- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following aging effects associated with electrical commodities require management.

- Increased resistance of connection
- Loss of material
- Reduced insulation resistance (IR)

Aging Management Programs

The following aging management programs 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 EQ 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 Instrumentation and Control Cables Not Subject to 10 CFR 50.49 EQ 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)
- Fuse Holders (B.2.3.41)
- Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.42)
- High-Voltage Insulators (B.2.3.43)

3.6.2.2 Further Evaluation of Aging Management as Recommended by GALL-SLR

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 HNP 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 (GALL) for Subsequent License Renewal (SLR) 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 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. 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 but are subject to TLAA evaluation.

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 metal-enclosed bus (MEB) which is similar in construction to an MEB, but instead of segregated or non-segregated electrical buses, cable bus is comprised of a metallic cable tray enclosure that utilizes three-phase insulated power cables installed on insulated support blocks (solid elastomeric material). HNP utilizes cable bus for the circuits between the Start-Up Transformers and the 4160 Emergency buses (E/F/G). The cable bus is comprised of a duct arrangement with metallic solid side walls and tight mesh-type top and bottom panels (to allow for ventilation and to prevent moisture retention).

The in-scope cable bus is routed from the Start-Up Transformers (1C/1D/1E and 2C/2D/2E) to the 4.16 kV buses (1E/1F/1G and 2E/2F/2G). The cable bus is in a ductwork fabricated of aluminum with stainless steel hardware used for duct section connections. The cable bus is run both indoors and outdoors at HNP.

<u>Loss of Resistance (Insulation Degradation)</u>

The cable bus is routed above ground, in aluminum ductwork, and the cable sections are supported (internal to the duct) by solid UV-resistant black HDPE supports, with holes for the cable to pass through, approximately 6 to 8 feet apart. These feed-through supports have excellent compressive strength and have been in widespread use in electrical bus work for many years. The ductwork has lenses for the use of infrared thermography. The aluminum ductwork is held together with stainless steel and steel hardware. For the outside installations, the cable bus will be exposed to weather (ambient temperature and humidity), but is shielded from direct sunlight (UV). The cable is jacketed and insulated and has no aging mechanisms in this location. Dirt and debris are not expected to be an issue because the mesh in the bottom panel are not large and gravity will generally prevent entry of any dirt beyond minor surface dust. Moisture could enter the duct (via heavy rain), but it will have no impact on the insulated cable bus because it cannot collect in the duct, as it will drain out the mesh at the bottom. The cable sections are spliced in Tap Boxes (with bolted splices and Raychem/Tyco cover materials) and will not be impacted by dirt/dust, minor debris, or transient moisture (intermittent rain or high humidity). There is one duct section which runs in a trench (but is above ground) which the U1 Main, Unit AUX 1A and 1B, and SAT 1C travel over. The duct could experience some minor intrusion of dust and dirt, but this will not collect and will not impact the jacketed and insulated power cables.

For the cable bus routed indoors, the ductwork is also routed above ground. There is no pathway for moisture to collect in the ductwork, and any dirt that enters the duct will be minor surface dust only. The insulated cables (and cable section splices) will not be impacted by minor surface dust or by the ambient temperature and humidity levels; the air-indoor environment is considered a benign environment for insulated cable (and the aluminum enclosures).

Therefore, there are no aging mechanisms present to cause degradation of the insulated cable bus (in its ductwork installation). The cable bus ductwork itself (and its external supports) will be addressed by the Structures Monitoring Program (B.2.3.33), for any applicable aging management.

Degradation of Connection / Loss of Torque (Cable Connections)

The cable connections for the in-scope insulated cable bus, at the termination ends of the power cables (at the Start-Up Transformers and at the 4.16 kV switchgear, and any cable connections internal to the cable routing) utilize hardware that includes Belleville (conical) washers, which prevent the degradation of the mechanical connections due to vibration or any potential heat stresses, thereby ensuring a sound electrical connection. Routine plant thermography inspections are performed on medium-voltage electrical terminations (at the transformers and the switchgear) to identify any possible points of increased resistance. These connections are associated with the active components at the termination ends, the applicable transformers, and the switchgear.

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).

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 (those are addressed separately). Major active equipment assemblies include their associated transmission conductor terminations.

Transmission conductors are subject to aging management review if they are necessary for recovery of offsite power following an SBO event. The power path for restoration of offsite power following an SBO event utilizes line connections with 45/7, 1113 thousands of circular mils (MCM) ACSR conductor (diameter 1.096 in) for the overhead lines between the Unit 1 and Unit 2 230 kV circuit breakers and each unit's high voltage startup transformer, among other sizes and types. The Unit 1 and Unit 2 230kV circuit breakers demarcate the SBO switchyard boundary for SLR. Other transmission conductors (and pathways - such as those through the unit auxiliary transformers) are not subject to AMR since they do not perform or support SLR intended functions. The offsite preferred power pathway for HNP is through the Start-Up Transformers. HNP units have two switchyards, a 500 kV switchyard and a 230 kV switchyard. Only the 230 kV switchyard is in the scope for SLR (the offsite power pathway is from the 230 kV switchyard to the emergency buses). The 230 kV switchyard used a breaker-and-a-half scheme, with multiple switchyard breakers in between Main Bus 1 and Main Bus 2 (in the switchyard). See Figure 2.5-1 for simplified sketch of the SBO offsite power pathway (from the 230 kV switchyard to the Start-Up Transformers, and then on to the 4.16 kV buses).

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 insulators. Switchyard bus is subject to AMR if it is necessary for recovery of offsite power following an SBO event. At HNP, switchyard bus associated with Main Bus 1 and Main Bus 2 in the 230 kV switchyard supports the offsite power pathway for SBO recovery. The arrangement is shown in the simplified sketch in Figure 2.5-1. Other switchyard bus is not subject to AMR since it does not perform or support SLR intended functions.

<u>Loss of Material (Wear due to wind-induced abrasion)</u>

Wind loading can cause transmission conductor vibration, or sway. At HNP, the connections between the 230 kV circuit breakers and the high-voltage station startup transformers are made by overhead transmission conductor lines (ACSR). Wind loading that can cause a transmission line and insulators to vibrate or sway are not applicable to the relatively short length of transmission conductor lines utilized at HNP. As a result, loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not aging effects requiring management because they are precluded by the length of the transmission conductor lines. 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 unique aging effects for transmission conductors.

Switchyard bus is connected to active equipment by short sections of flexible conductors. The rigid bus does not vibrate because it is supported by station post insulators and ultimately by static, structural components such as concrete footings and structural steel. The flexible conductors dampen the minor vibrations associated with the active switchyard components to the switchyard bus. As a result, loss of material (wear) caused by switchyard bus vibration is not an aging effect requiring management because it is precluded by design.

Therefore, loss of material due to wear of transmission conductors and switchyard bus is not an aging effect requiring management at HNP.

Loss of Conductor Strength (Corrosion)

This aging effect applies to all aluminum conductor steel reinforced (ACSR) transmission conductors. In-scope transmission conductors at HNP are limited to short length (~500 ft.) transmission line connections of 1113 MCM ACSR cable between the Unit 1 and Unit 2 230 kV circuit breakers and each unit's high-voltage startup transformer used for recovery of offsite power following an SBO event. The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the aluminum strand. With respect to corrosion resistance, aluminum is more resistant than steel. Aluminum quickly forms an oxide layer which protects the material underneath and this layer will re-form if damaged (in the absence of environmental stress). A layer of approximately 1 nanometer (10 angstroms) is sufficient to protect the metal underneath. Aluminum is lighter than steel and provides a much higher strength-to-weight ratio.

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, potential seaside atmospheric conditions, and general meteorological conditions. Air quality in rural areas, such as the area surrounding HNP, generally contains low concentrations of suspended particles and SO_2, which minimize the corrosion rate. There are no major industries within the immediate vicinity of HNP.

The HNP site is located near Baxley, Georgia along the Altamaha River.

Regarding the loss of strength of transmission conductors, tests performed by Ontario Hydroelectric showed a 30% loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion.

There is a 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% of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. These requirements are reviewed concerning the specific conductors included in the aging management review.

The transmission conductor at HNP with the smallest design margin for strength utilizes a 45/7-strand 1113 MCM ACSR conductor (diameter 1.096 in.) for the overhead lines from the 230 kV switchyard to the startup transformers. The ultimate strength for the 45/7-strand ACSR is 29,800 lbs. The Ontario Hydroelectric study showed a 30% loss of composite conductor strength in an 80-year old conductor. In the case of the 45/7-strand ACSR transmission conductors, a 30% reduction in ultimate strength would yield an adjusted (aged) ultimate strength of 20,860 lbs. Under the NESC for transmission conductor, there is a limit on maximum tension design of 35% of the ultimate strength, so the maximum allowable tension strength for the lines is 10,430 lbs. With a reduction in ultimate strength to 20,860 lbs., there would still be a substantial margin between the reduced (aged) ultimate strength of 20,860 lbs. and the maximum tension strength permitted at HNP of 10,430 lbs. (a margin of 50%).

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 unique aging effects for transmission conductors.

Therefore, loss of conductor strength is not an aging effect requiring management for transmission conductors at HNP.

<u>Increased Resistance of Connection (Corrosion)</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, copper, and aluminum alloy components in the 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 or support their SLR intended function. At HNP, 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 site-specific and industry wide OE, this method of installation has proven to provide a corrosion-resistant low electrical resistance connection. In addition, HNP periodically performs infrared inspections of the 230 kV switchyard connections to verify the integrity of the connections. The infrared inspections of the 230 kV 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 HNP.

Therefore, increased connection resistance due to general corrosion resulting from oxidation of switchyard connection metal surfaces is not an aging effect requiring management at HNP.

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 Electric Power Research Institute (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.

For bolted connections between transmission conductors and switchyard bus, in-scope transmission conductors at HNP are limited to the transmission line connections between the 230 kV circuit breakers and each unit's high-voltage station startup transformer used for recovery of offsite power following an SBO event. Routine inspections of the switchyard and startup 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 demonstrate that this aging effect is not significant for HNP.

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 HNP.

Conclusion

There are no applicable aging effects that could cause a loss of the intended function of the transmission conductor connections and switchyard bus connections for the SPEO. Therefore, there are no aging effects requiring management for transmission conductors and switchyard bus connections.

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).

Quality Assurance provisions applicable to SLR for HNP 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 GALL-SLR

3.6.2.3.1 Fuse Holders

The fuse holders are addressed in Section 2.5.2. There are boxes which contain only fuses and terminal blocks (i.e., passive electrical enclosures) which require evaluation / inspection to determine if there are any stressors / aging mechanisms / aging effects present, and to determine if the fuses are manipulated more than once per cycle, which could induce fatigue in the fuse clip. The in-scope fuse holders are included in the Fuse Holders AMP (B.2.3.41), which will manage any degradation associated with the insulating block (terminal block) of the subject fuse holders, and also manage any degradation associated with the metallic clamp of the fuse holder.

3.6.2.3.2 High-Voltage Insulators

The high-voltage insulators for Hatch are included in the High-Voltage Insulators AMP (B.2.3.43), which will manage any aging degradation for the in-scope HV insulators (those in the SBO offsite power pathway). This AMP will manage any degradation associated with loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind or due to reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination.

3.6.2.3.3 Metal-Enclosed Bus

The in-scope MEB (bus bar) at Hatch is found in 30’ bus sections for Units 1 and 2, located in the Control Building. The bus bar is made of copper and is insulated with mylar and coated with urethane. The bus joints are plated. These MEB sections are made of armor-clad ductwork (tightly-sealed duct) that is comprised of galvanized steel and is coated with paint. The ductwork is located in a controlled environment, with a maximum temperature of 104°F and with relative humidity levels between 40% and 80%.

The MEB is almost never loaded - the bus is used for an alternative electrical alignment relative to buses F and G, and is available for use to align 4160 volt bus F to 600 volt buses C and D, in the event of an SBO.

The MEB is not subject to moisture intrusion, it is not subject to thermal cycling, it is not subject to the presence of dirt or debris. The MEB is connected to static equipment that does not normally vibrate, such as switchgear and disconnect switches. The MEB is supported by structural steel. The ductwork bolts utilize Belleville washers, to ensure a tight closure. The copper bus bar is insulated and sealed. Because the bus design precludes any potential aging effects, the discrete MEB sections do not require an aging management program, as described in 10 CFR 54.21(a)(3) - the integrated plant assessment (IPA) process evaluates that no aging mechanisms or effects are present.

3.6.2.4 Time-Limited Aging Analysis

The TLAAs identified below are associated with the electrical commodities:

- Section 4.4, *Environmental Qualification of Electrical Equipment*

3.6.3 Conclusion

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 effective managed.

Based on the demonstrations 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 Program / TLAA	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 aging 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 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 of Electric Components", of this report for meeting the requirements of 10 CFR 54.21(c)(1)(i)-(iii).	Yes (SRP-SLR Section 3.6.2.2.1)	Consistent with NUREG-2191. EQ equipment is subject to replacement based on a qualified life. EQ analyses are evaluated as TLAAs in Section 4.4. Further evaluation is documented in Section 3.6.2.2.1.
3.6-1, 002	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers; silicone rubber; fiberglass; and aluminum alloy exposed to air - outdoor	Loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	AMP XI.E7,"High-Voltage Insulators"	No	Consistent with NUREG-2191. Further evaluation is documented in Section 3.6.2.3.2.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 003	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers; silicone rubber; 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	Consistent with NUREG-2191. Further evaluation is documented in Section 3.6.2.3.2.
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 Hatch. Further evaluation is documented in Section 3.6.2.2.3.
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 Hatch. Further evaluation is documented in Section 3.6.2.2.3.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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 Hatch. Further evaluation is documented in Section 3.6.2.2.3.
3.6-1, 007	Transmission conductors composed of aluminum; steel exposed to air - outdoor	Loss of material due to wind-induced abrasion	A plant-specific aging management program is to be evaluated for All Aluminum Conductor (AAC), ACAR, and ACSR (aluminum conductor steel reinforced)	Yes, (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to Hatch. Further evaluation is documented in Section 3.6.2.2.3.
3.6-1, 008	Electrical insulation for electrical cables and connections (including terminal blocks, etc.) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an 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.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 010	Electrical conductor insulation for inaccessible power, instrumentation, and control cables (e.g., installed in duct bank, buried conduit or direct buried) composed of various organic polymers (such as EPR, SR, EPDM, XLPE, and butyl rubber), 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 Instrumentation 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 Instrumentation 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.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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	Not applicable. The in-scope metal enclosed bus at Hatch is armor-clad and is not subject to these aging effects. Further evaluation is documented in Section 3.6.2.3.3.
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	Not applicable. The in-scope metal enclosed bus at Hatch is armor-clad and is almost never loaded and is not subject to these aging effects. Further evaluation is documented in Section 3.6.2.3.3.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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	Not applicable. The in-scope metal enclosed bus at Hatch is armor-clad and is almost never loaded and is not subject to these aging effects. Further evaluation is documented in Section 3.6.2.3.3.
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	Not applicable. The in-scope metal enclosed bus at Hatch is comprised of galvanized steel and is located in a controlled environment and is not subject to these aging effects. Further evaluation is documented in Section 3.6.2.3.3.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 015	Metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air - outdoor	Loss of material due to pitting, crevice corrosion	AMP XI.E4, “Metal Enclosed Bus” or AMP XI.S6, "Structures Monitoring"	No	Not applicable. The in-scope metal enclosed bus at Hatch is located in an indoor controlled environment. Further evaluation is documented in Section 3.6.2.3.3.
3.6-1, 016	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air - indoor, uncontrolled	Increased electrical resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply)	AMP XI.E5, “Fuse Holders” No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms and effects due to chemical contamination, corrosion, and oxidation.	No	Consistent with NUREG-2191 Further evaluation is documented in Section 3.6.2.3.1.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 017	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air - indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue from ohmic heating, thermal cycling, electrical transients	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue due to ohmic cheating, thermal cycling, electrical transients.	No	Consistent with NUREG-2191. Further evaluation is documented in Section 3.6.2.3.1.
3.6-1, 018	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air - indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/ manipulation or vibration	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue caused by frequent fuse removal/manipulation or vibration	No	Consistent with NUREG-2191. Further evaluation is documented in Section 3.6.2.3.1.
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.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.6-1, 020	Not applicable. This line item only applies to PWRs.				
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 Hatch. Further evaluation is documented in Section 3.6.2.2.3.
3.6-1, 022	Fuse holders (not part of active equipment): insulation material composed of electrical insulation material: bakelite; phenolic melamine or ceramic; molded polycarbonate, and other, exposed to air - indoor, controlled or uncontrolled	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms	No	Consistent with NUREG-2191. Further evaluation is documented in Section 3.6.2.3.1.
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.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.6-1, 024	Metal enclosed bus: external surface of enclosure assemblies. Steel air - indoor controlled	None	None	No	Consistent with NUREG-2191.
3.6-1, 027	Cable bus: external surface of enclosure assemblies galvanized steel; aluminum; air - indoor controlled or uncontrolled	None	None	No	Consistent with NUREG-2191.
3.6-1, 029	Cable bus: electrical insulation; insulators - exposed to air - indoor controlled or uncontrolled, air - outdoor	Reduced electrical insulation resistance due to degradation caused thermal/ thermoxidative degradation of organics and photolysis (UV sensitive materials only) of organics, moisture/debris intrusion and ohmic heating	A plant-specific aging management program is to be evaluated	Yes, (SRP-SLR Section 3.6.2.2.2)	NUREG-2191 aging effects are not applicable to Hatch. Further evaluation is documented in Section 3.6.2.2.2.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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	Hatch cable bus duct is constructed of aluminum and these aging effects are not applicable. Further evaluation is documented in Section 3.6.2.2.2.
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	AMP XI.S6, “Structures Monitoring”	Yes	Consistent with NUREG-2191. The Structures Monitoring Program (B.2.3.33) will manage any aging effects.
3.6-1, 032	Cable bus: external surface of enclosure assemblies: composed of steel; air - indoor controlled	None	None	No	Not applicable. The Hatch cable bus duct is constructed of aluminum.

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary 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 bus	Insulate (electrical)	Electrical insulation; insulators	Air – indoor controlled Air – indoor uncontrolled Air – outdoor	None	None	VI.A.L-11	3.6-1, 029	I, 5
Cable bus: External surface of enclosure assemblies	Electrical continuity	Galvanized steel Aluminum	Air – indoor controlled Air – indoor uncontrolled	None	None	VI.A.L-09	3.6-1, 027	A
Cable bus: External surface of enclosure assemblies	Electrical continuity	Galvanized steel Aluminum	Air – outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring Program (B.2.3.33)	VI.A.L-13	3.6-1, 031	E, 6
Cable connections (Metallic parts)	Electrical continuity	Various metals used for electrical contacts	Air – indoor controlled Air – indoor uncontrolled Air – outdoor	Increased electrical resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, oxidation	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

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
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 such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket / insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance (IR) or degraded dielectric strength due to significant moisture	Electrical Insulation for Inaccessible Instrumentation 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 such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket / insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance (IR) or degraded dielectric Strength due to significant moisture	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								
Component Type	**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 such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/ insulation shield	Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance (IR) or degraded dielectric strength due to significant moisture	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, Insulate (electrical)	Various metallic materials, various polymeric materials	Adverse localized environment	Various aging effects	Environmental Qualification of Electric Equipment (Section 4.4)	VI.B.L-05	3.6-1, 001	A
Electrical insulation for electrical cables and connections (including terminal blocks, etc.)	Insulate (electrical)	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	Adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance (IR) due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	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

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Component Type	**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 used in instrumentation circuits that are sensitive to reduction in conductor electrical insulation resistance (IR)	Insulate (electrical)	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	Adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance (IR) due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	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)	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 poly-carbonate; Other	Air – indoor uncontrolled Air – outdoor	Reduced electrical insulation resistance (IR) due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Fuse Holders (B.2.3.41)	VI.A.LP-24	3.6-1, 022	A
Fuse holders (not part of active equipment): metallic clamps	Electrical continuity	Various metals used for electrical connections	Air – indoor uncontrolled Air – outdoor	Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/ manipulation or vibration	Fuse Holders (B.2.3.41)	VI.A.LP-31	3.6-1, 018	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Component Type	**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	Increased electrical resistance of connection due to fatigue due to ohmic heating, thermal cycling, electrical transients	Fuse Holders (B.2.3.41)	VI.A.LP-07	3.6-1, 017	A
Fuse holders (not part of active equipment): metallic clamps	Electrical continuity	Various metals used for electrical connections	Air – indoor uncontrolled Air – outdoor	Increased electrical resistance of connection due to chemical contamination, corrosion, and oxidation	Fuse Holders (B.2.3.41)	VI.A.LP-23	3.6-1, 016	A
High-voltage electrical insulators	Insulate (electrical)	Porcelain; Malleable iron; Aluminum; Galvanized steel; Cement, Polymers, Silicone rubber; Aluminum alloy	Air – outdoor	Loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	High-Voltage Insulators (B.2.3.43)	VI.A.LP-32	3.6-1, 002	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Component Type	**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, Polymers, Silicone rubber; Aluminum alloy	Air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination	High-Voltage Insulators (B.2.3.43)	VI.A.LP-28	3.6-1, 003	A
Metal-enclosed bus	Electrical continuity	Galvanized steel	Air – indoor controlled	None	None	VI.A.LP-41	3.6-1, 023	A
Metal-enclosed bus	Electrical continuity	Galvanized steel	Air – indoor controlled	None	None	VI.A.LP-44	3.6-1, 024	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, 1
Transmission conductors	Electrical continuity	Aluminum; Steel	Air – outdoor	None	None	VI.A.LP-38	3.6-1, 004	I, 3
Transmission conductors	Electrical continuity	Aluminum; Steel	Air – outdoor	None	None	VI.A.LP-47	3.6-1, 007	I, 4
Transmission conductors	Electrical continuity	Aluminum; Steel	Air – outdoor	None	None	VI.A.LP-48	3.6-1, 005	I, 2

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.

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.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable

Plant Specific Notes

1. Based on Hatch design and a review of OE, loss of material and increased resistance of connection are not applicable aging effects for Hatch switchyard bus and connections. Hatch 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.

2. Based on Hatch design and a review of OE increased resistance of connection is not an applicable aging effect for Hatch transmission connectors. Hatch 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.

3. Based on Hatch design and a review of OE loss of conductor strength is not an applicable aging effect for Hatch ACSR and AAC transmission conductors. Hatch ACSR and AAC 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.

4. Based on Hatch design and a review of OE loss of material is not an applicable aging effect for Hatch ACSR and AAC transmission conductors. Hatch ACSR and AAC transmission conductors within the scope of license renewal are not subject to wind-induced abrasion. See SLRA Section 3.6.2.2.3 for additional information.

5. Based on Hatch design and a review of OE, cable inside the bus does not have any applicable AERM. See SLRA Section 3.6.2.2.2 for additional information.

6. The Structures Monitoring AMP (B.2.3.33) will manage the aging effects for the ductwork in an air-outdoor environment.

4.0 TIME-LIMITED AGING ANALYSES

This section presents descriptions of the Time-Limited Aging Analyses (TLAAs) and exemptions for Hatch Nuclear Plant (HNP) in accordance with 10 CFR 54.3(a) and 10 CFR 54.21(c). Section 4 is divided into Sections 4.1 through 4.8. Several 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 HNP 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, Concrete Containment Tendon Prestress
- Section 4.6, Containment Liner Plate, Metal Containments, and Penetrations Fatigue
- Section 4.7, Other Plant-Specific TLAAs

Section 4.8 contains the references used to support the TLAAs.

4.1 IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES AND EXEMPTIONS

Pursuant to 10 CFR 54.3, TLAAs are defined as those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);

(2) Consider the effects of aging;

(3) Involve time-limited assumptions defined by the current operating term, for example 40 years;

(4) Were determined to be relevant by the licensee in making a safety determination;

(5) Involve conclusions or 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 Identification of Time-Limited Aging Analyses

TLAAs have been identified for HNP 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 NRC guidance, industry guidance, and experience including:

- NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” Draft Revision 1, July 2023
- NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants,” Draft Revision 1, July 2023
- 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 subsequent license renewal applications, NRC Requests for Additional Information, and NRC Safety Evaluation Reports (SERs) for these applications
- Plant-specific document reviews

CLB and design basis documents (DBDs) were searched to identify potential TLAAs. The document search included the following:

- Final Safety Analysis Reports (Unit 1 and Unit 2 FSARs)
- Technical Specifications and Bases (TS and TSB)
- HNP License Renewal Application (LRA) including associated RAI responses, plus the associated NRC Safety Evaluation Report (SER)
- Calculations and design reports referenced in the FSAR, TS, and TSB

- 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 SPEO. 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 HNP. Those with a “Yes” entry apply to HNP and the SLRA section where they are evaluated is provided. Those with a “No” entry do not apply to HNP. Additional plant-specific TLAAs that met all six criteria are included in Table 4.1-2.

HNP also reviewed previous SLRAs and requests for additional information to determine if a TLAA evaluated for another plant was applicable to HNP. No potential TLAAs from other SLRAs applicable to HNP were identified.

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 HNP?	SLRA Section
NUREG-2192, Table 4.1-2 Generic Time-Limited Aging Analyses		
Neutron Fluence	Yes	4.2.1
Pressurized Thermal Shock (PWRs Only)	No	N/A
Upper Shelf Energy (PWRs and BWRs)	Yes	4.2.2
Pressure-Temperature (P-T) Limits (PWRs and BWRs)	Yes	4.2.4
Low Temperature Overpressure Protection System Setpoints (PWRs Only)	No	N/A
Ductility Reduction Evaluation for Reactor Internals (B&W designed PWRs only)	No	N/A
RPV Circumferential Weld Relief–Probability of Failure and Mean Adjusted Reference Temperature Analysis for the RPV Circumferential Welds (BWRs only)	Yes	4.2.5
Reactor Vessel Axial Weld Probability of Failure and Mean Adjusted Reference Temperature Analysis (BWRs only)	Yes	4.2.6
Metal Fatigue of Class 1 Components	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	Yes(1)	4.3.8
Cycle-dependent Fracture Mechanics or Flaw Evaluations	Yes(2)	4.3.9
Cycle-dependent Fatigue Waivers	Yes	4.3.2
Environmental Qualification (EQ) of Electrical Equipment	Yes	4.4
Concrete Containment Tendon Pre-stress	No(3)	4.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes	4.6
NUREG-2192, Table 4.7-1 – Examples of Potential Plant-Specific TLAA Topics (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	No(4)	N/A
Loss of preload for core plate rim hold down bolts	No(5)	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 HNP?	SLRA Section
Erosion of the main steam line flow restrictors	No	N/A
Susceptibility to irradiation-assisted stress corrosion cracking (IASCC)	Yes	4.2.8
Fatigue of cranes (crane cycle limits)	Yes	4.7.1
Fatigue of the spent fuel pool liner	No	N/A
Corrosion allowance calculations	Yes	4.7.2
Flaw growth due to stress corrosion cracking (SCC)	No(6)	N/A
Predicted lower limit	No	N/A

Notes:

(1) High energy line break (HELB) based on fatigue cumulative usage factor (CUF) is a TLAA for HNP SLR. HELB analyses are included in the fatigue analysis per the HNP LRA SER, NUREG-1803, (Reference 4.8.26) page 1-38. Break locations were postulated based on stress criteria for high energy lines outside containment.

(2) The HNP Unit 1 reactor pressure vessel (RPV) closure head dollar plate weld indication # 16 meets the fracture mechanics requirements of ASME XI IWB-3612.

(3) The HNP containment design does not employ prestressed concrete tendons. The primary containment consists of the drywell, the suppression chamber, a connecting vent system, a vacuum relief system, containment cooling systems, and other service equipment.

(4) Core shroud reflood is not in the HNP CLB and was not identified in the HNP LRA.

(5) Loss of preload for core plate rim hold down bolts is not part of the CLB and is not a TLAA for HNP. Both units employ wedges to structurally replace the lateral load resistance provided by the rim hold-down bolts.

(6) For superior resistance to intergranular stress corrosion cracking (IGSCC) in primary loop, a highly corrosion resistant stainless steel, Type 316 Nuclear Grade, was used for systems such as the replacement recirculation system piping, portions of residual heal removal (RHR) piping, and reactor water cleanup (RWCU) piping.

4.1.2 Evaluation of 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 compared 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 a LRA must contain the following information:

> *(c) An evaluation of time-limited aging analyses.*
>
> > *(1) A list of time-limited aging analyses, as defined in section 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 HNP. The disposition methods used are described in each TLAA evaluation section.

4.1.4 Summary of Results

Several categories of TLAAs were identified for HNP. 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 – HNP 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
Reactor Pressure Vessel (RPV) Neutron Fluence	10 CFR 54.21(c)(1)(iii)	4.2.1.1
Reactor Vessel Internals (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
Susceptibility to IASCC	10 CFR 54.21(c)(1)(iii)	4.2.8
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

Table 4.1-2
Summary of Results – HNP Time-Limited Aging Analysis

TLAA Description	Disposition	SLRA Section
Fatigue Analysis of RPV Internals	10 CFR 54.21(c)(1)(iii)	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 and Associated Line Break Analyses	10 CFR 54.21(c)(1)(i)	4.3.6
Environmentally-Assisted Fatigue	10 CFR 54.21(c)(1)(iii)	4.3.7
High Energy Line Break Analyses Based on Cumulative Fatigue Usage	10 CFR 54.21(c)(1)(iii)	4.3.8
Cycle-dependent Fracture Mechanics or Flaw Evaluations	10 CFR 54.21(c)(1)(ii)	4.3.9
Environmental Qualification (EQ) of Electric Components	10 CFR 54.21(c)(1)(iii)	4.4
Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses		4.6
Fatigue Analysis of the Vessel Shell to Ring Girder	10 CFR 54.21(c)(1)(iii)	4.6.1
Fatigue Exemption (Waivers) for Main Steam Penetration Backing Ring and Containment Penetrations	10 CFR 54.21(c)(1)(iii)	4.6.2
Other Plant-Specific Time-Limited Aging Analyses		4.7
Fatigue of Cranes (Crane Cycle Limits)	10 CFR 54.21(c)(1)(i)	4.7.1
Corrosion Allowance Calculations	10 CFR 54.21(c)(1)(iii)	4.7.2

4.1.5 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 TLAAs 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.

To identify exemptions for HNP, a keyword search was conducted. The HNP Units 1 and 2 FSARs and TS, 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 utilized key terms, including “50.12,” “exemption,” “waiver,” “N-415.1,” and “NB-3222.4.”

There are no 10 CFR 50.12 exemptions involving TLAAs as defined in 10 CFR 54.3 identified for the SPEO.

Exemptions related to the spent fuel dry cask storage are not included since SNC utilizes the general license for spent fuel storage in an independent spent fuel storage installation (ISFSI) in accordance with 10 CFR 72, Subpart K. This is separate from the operating license issued per 10 CFR Part 50.

Fatigue waivers for ASME Class 1 components are documented in Section 4.3.2. Additionally, a fatigue exemption analysis of the backing ring for the HNP Unit 1 main steam containment penetrations and for the HNP containment and containment penetrations is included in Section 4.6.2. However, these are not 10 CFR 50.12 exemptions.

4.2 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 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 TLAAs. This group of TLAAs concerns the effect of irradiation embrittlement on the beltline and extended beltline regions of the HNP reactor vessels, 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 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 using operating P-T limits that are included in the HNP Pressure and Temperature Limits Reports (PTLRs). 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 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 or extended 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 also been identified that is based upon irradiated material properties derived using neutron fluence values as inputs. The following TLAAs related to neutron embrittlement are evaluated in the SLRA sections listed below:

- Neutron Fluence Projections (4.2.1)
- RPV Materials Upper Shelf Energy (USE) Reduction due to Neutron Embrittlement (4.2.2)
- Adjusted Reference Temperature (ART) for RPV Materials due to Neutron Embrittlement (4.2.3)
- RPV Thermal Limit Analysis: Operating Pressure-Temperature (P-T) 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)
- Susceptibility to IASCC (4.2.8)

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 HNP 80-year SPEO.

Radiation Analysis Modeling Application (RAMA) methodology was used to develop fluence projections for RPV and internal (RVI) components for 80 years, corresponding to 68.6 EFPY for Unit 1, and 66 EFPY for Unit 2. These fluence projections are used to evaluate TLAAs in SLRA Sections 4.2.2 through 4.2.8. The basis for acceptability of each of these fluence projection methods is described in the applicable sections below.

HNP Power Level History

Below is a summary of HNP Unit 1 historical operating power levels which have been considered in developing the 80-year fluence projections:

- Original licensed operating power of 2436 MWt
- Power uprate to 2558 MWt at the beginning of Cycle 17
- Second power uprate to 2763 MWt at the beginning of Cycle 19.
- Reactor Operating Pressure Increase (ROPI) power uprate to 2804 MWt at the beginning of Cycle 22

Below is a summary of HNP Unit 2 historical operating power levels which have been considered in developing the 80-year fluence projections:

- Original licensed operating power of 2436 MWt
- Power uprate to 2558 MWt at the beginning of Cycle 13
- Second power uprate to 2763 MWt at the beginning of Cycle 15
- ROPI power uprate to 2804 MWt at the beginning of Cycle 18

4.2.1.1 Reactor Pressure Vessel (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 USE, ART, P-T limits, axial and circumferential weld failure probability, and RPV reflood thermal shock.

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 HNP Unit 1 and Unit 2 RPVs for the extended licensed operating periods using the Electric Power Research Institute, Inc.'s (EPRI) RAMA Fluence Methodology. The RAMA Fluence Methodology (hereafter referred to as "RAMA") received generic approval from the U.S. NRC (Reference 4.8.35) for determining fast neutron fluence in BWR and PWR pressure vessels compliant with the requirements of Regulatory Guide (RG) 1.190 (Reference 4.8.2) for neutron flux evaluation, as stated in HNP Unit 2 FSAR, Section 4.1.4.4. These current fluence analyses have been identified as TLAAs that require evaluation for the SPEO.

TLAA Evaluation

The information in this RPV fluence evaluations for SLR was generated based upon the RAMA Fluence Methodology. The neutron fluence calculated for both HNP Unit 1 and Unit 2 reactors is based on historical and projected reactor operating state conditions:

- Unit 1's historical fluence was calculated from reactor exposure data accumulated to the end of Cycle 30 (EOC30), or 37.6 EFPY of reactor operation. Neutron fluence projections were performed to 80 years of licensed operation, or 68.6 EFPY of reactor operation based on operating data for a part-historical, part-projection Cycle 31. The last cycle, Cycle 32, is a full projection cycle. It is assumed to be the equilibrium cycle for projecting fluence to the end of the reactor's 80-year licensed period of operation. The 68.6 EFPY was calculated assuming the equilibrium cycle with an average capacity factor of 95%.

- Unit 2's historical fluence was calculated from reactor exposure data accumulated to the end of Cycle 27 (EOC27), or 35.9 EFPY of reactor operation. Neutron fluence projections were performed to 80 years of licensed operation, or 66.0 EFPY of reactor operation based on operating data for a part-historical, part-projection Cycle 28. The last cycle, Cycle 28, is a projection cycle that is comprised of partial-historical, partial-projection data. This cycle is assumed to be the equilibrium cycle for projecting fluence to the end of the reactor’s 80-year licensed period of operation. The 66.0 EFPY was calculated assuming the equilibrium cycle with an average capacity factor of 95%.

In compliance with RG 1.190, HNP has benchmarked the RAMA Fluence Methodology against industry standard benchmarks and plant-specific dosimetry measurements for BWRs and PWRs. RAMA is described in the Boiling Water Reactor Vessel Internals Project (BWRVIP) BWRVIP-114NP-A (Reference 4.8.3).

The results of the benchmarking show that the fluence methodology can predict specimen activities with no discernable bias in the computed fluence. It was determined that the combined uncertainty for the HNP RPVs is 9.3 percent for Unit 1 and 9.5 percent for Unit 2. Based upon these results, there is no discernable bias in the computed RPV fluence for the period of Cycle 1 through the end of Cycle 30 for HNP Unit 1 or through the end of Cycle 27 for Unit 2.

NUREG-2191 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-145-A, “BWR Vessel and Internals Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Materials Sample Using RAMA Fluence Methodology” (Reference 4.8.4). 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 HNP is identical to that described in BWRVIP-145-A.

Maximum best-estimate fast neutron damage fluence, or “maximum damage fluence” is specifically reported for the following RPV components. Figures 4.2.1.1-1a and 4.2.1.1-1b illustrate the location of the welds, shell plates, and nozzles in the RPV.

- RPV Welds:
  - The maximum damage fluence is reported at 0T, 1/4T, 3/4T, and 1T for the following horizontal and vertical welds in the RPV extended beltline region:

    Unit 1: C-3, C-4, C-2-A, C-2-B, C-2-C, C-3-A, C-3-B, C-3-C, C-4-A, C-4-B, and C-4-C

    Unit 2: 2C-3, 2C-4, 2C-2-A, 2C-2-B, 2C-2-C, 2C-3-A, 2C-3-B, 2C-3-C, 2C-4-A, 2C-4-B, and 2C-4-C

- RPV Shell Courses:
  - Unit 1: The maximum damage fluence is reported at 0T, 1/4T, 3/4T, and 1T for the following shells in the RPV extended beltline region: Lower (Shell 4), Lower-Intermediate (Shell 3), and Upper-Intermediate (Shell 2) for Unit 1.

- Unit 2: The maximum damage fluence is reported at 0T, 1/4T, 3/4T, and 1T for the following shells in the RPV extended beltline region: Lower (Shell 1), Lower-Intermediate (Shell 2), and Upper-Intermediate (Shell 3) for Unit 2.

- RPV Nozzles and Extraction Paths:

  - The maximum damage fluence is reported at 0T, 1/4T, 3/4T, and 1T for the N2 and N16 nozzles along the forging-to-base metal welds and the N2 extraction path in the nozzle forgings for both Units 1 and 2.

The maximum damage fluence at 1/4T and 3/4T for each of the components listed above and in the tables within this section of the SLRA was calculated using a plant-specific displacements per atom (dpa) attenuation method of the reactor vessel components and their materials as prescribed and accepted in RG 1.99, Revision 2 (Reference 4.8.5) ($f_x = f_{surf} * dpa_x/dpa_{surf}$).

HNP Units 1 and 2 are both BWR/4 class reactors with a core loading of 560 fuel assemblies. Both historical and projected reactor operating data are used in the neutron fluence evaluations.

The fluence projections for both units are included at the end of this section. The Unit 1 tables are sequential and end in “a”, while the Unit 2 tables are also sequential and end in “b.” Figures 4.2.1.1-1a and 4.2.1.1-1b follow the same naming convention respective of Unit 1 or Unit 2.

Unit 1:

The fluence evaluation for the HNP-1 reactor uses fluence that is calculated at EOC 30 (37.6 EFPY) and an 80 reactor-year lifetime corresponding to 68.6 EFPY.

The HNP-1 fluence projections are provided in the following tables:

(1) Table 4.2.1.1-1a, Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 1 RPV Extended Beltline Welds at 68.6 EFPY.

(2) Table 4.2.1.1-2a, Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 1 RPV Extended Beltline Shell Plates.

(3) Table 4.2.1.1-3a, Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 1 RPV N2 Nozzles in the Extended Beltline Region.

(4) Table 4.2.1.1-4a, Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 1 RPV N16 Nozzles in the Extended Beltline Region.

(5) Table 4.2.1.1-5a, Reactor Pressure Vessel Beltline Elevation Range for the Hatch Unit 1 Reactor Vessel Wall.

Values in these tables are in standard black font, however, if the damage fluence exceeds the threshold fluence of 1.0×10^{17} n/cm^2, then it is shown in red font, except for the nozzles, where the highest damage fluence values below the threshold fluence of 1.0×10^{17} n/cm^2 are shown in blue font. The overall maximum damage fluences are in bold font.

Table 4.2.1.1-1a reports the highest damage fluence that is determined for the RPV horizontal and vertical welds at 68.6 EFPY. The maximum damage fluence for each weld is determined to occur at the inner surface (0T) of the RPV base metal, with the maximum damage fluence occurring in horizontal weld C-4 with a value of 2.96 x 10^{18} n/cm^2 at 68.6 EFPY.

Table 4.2.1.1-2a reports the highest damage fluence that is determined for each RPV shell plate at 68.6 EFPY. The maximum damage 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 3 with a value of 3.70 x 10^{18} n/cm^2 at 68.6 EFPY.

Table 4.2.1.1-3a reports the highest damage fluence that is determined for the RPV N2 nozzles at 68.6 EFPY. The maximum damage fluence for the N2 nozzles occurs at the inner surface (0T) of the RPV base metal with a value of 6.45 x 10^{16} n/cm^2 at 68.6 EFPY.

Table 4.2.1.1-4a reports the highest damage fluence that is determined for the RPV N16 nozzles at 68.6 EFPY. The maximum damage fluence for the N16 nozzles occurs at the inner surface (0T) of the RPV base metal with a value of 8.33 x 10^{17} n/cm^2 at 68.6 EFPY.

Table 4.2.1.1-5a reports the elevations that define the RPV extended beltline at 68.6 EFPY. It is shown that the RPV beltline at 68.6 EFPY is determined to cover 482.7 cm, or approximately 190.1 in, of the reactor vessel wall.

Unit 2:

The fluence evaluation for the HNP-2 reactor uses fluence that is calculated at EOC 27 (35.9 EFPY) and an 80 reactor-year lifetime corresponding to 66.0 EFPY.

The HNP-2 66.0 EFPY fluence projections are provided in the following tables:

(1) Table 4.2.1.1-1b, Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 2 RPV Extended Beltline Welds at 66.0 EFPY

(2) Table 4.2.1.1-2b, Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 2 RPV Extended Beltline Shell Plates

(3) Table 4.2.1.1-3b, Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 2 RPV N2 Nozzles in the Extended Beltline Region

(4) Table 4.2.1.1-4b, Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 2 RPV N16 Nozzles in the Extended Beltline Region

(5) Table 4.2.1.1-5b, Reactor Pressure Vessel Beltline Elevation Range for the Hatch Unit 2 Reactor Vessel Wall

Values in these tables are in standard black font, however, if the damage fluence exceeds the threshold fluence of 1.0 x 10^{17} n/cm^2, then it is shown in red font except for the nozzles, where the highest damage fluence values below the threshold fluence of 1.0 x 10^{17} n/cm^2 are shown in blue font. The overall maximum damage fluences are in bold font.

Table 4.2.1.1-1b reports the highest damage fluence that is determined for the RPV horizontal and vertical welds at 66.0 EFPY. The maximum damage fluence for each weld is determined to occur at the inner surface (0T) of the RPV base metal, with the maximum damage fluence occurring in horizontal weld 2C-4 with a value of 2.67 x 10^{18} n/cm^2 at 66.0 EFPY.

Table 4.2.1.1-2b reports the highest damage fluence that is determined for each RPV shell plate at 66.0 EFPY. The maximum damage 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 2 with a value of 3.56 x 10^{18} n/cm^2 at 66.0 EFPY.

Table 4.2.1.1-3b reports the highest damage fluence that is determined for the RPV N2 nozzles at 66.0 EFPY. The maximum damage fluence for the N2 nozzles occurs at the inner surface (0T) of the RPV base metal with a value of 7.91 x 10^{16} n/cm^2 at 66.0 EFPY.

Table 4.2.1.1-4b reports the highest damage fluence that is determined for the RPV N16 nozzles at 66.0 EFPY. The maximum damage fluence for the N16 nozzles occurs at the inner surface (0T) of the RPV base metal with a value of 8.15 x 10^{17} n/cm^2 at 66.0 EFPY.

Table 4.2.1.1-5b reports the elevations that define the RPV extended beltline at 66.0 EFPY. It is shown that the RPV beltline at 66.0 EFPY covers 487.2 cm, or approximately 191.8 in, 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. 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 HNP 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 Fluence Monitoring AMP (B.2.2.3) 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.

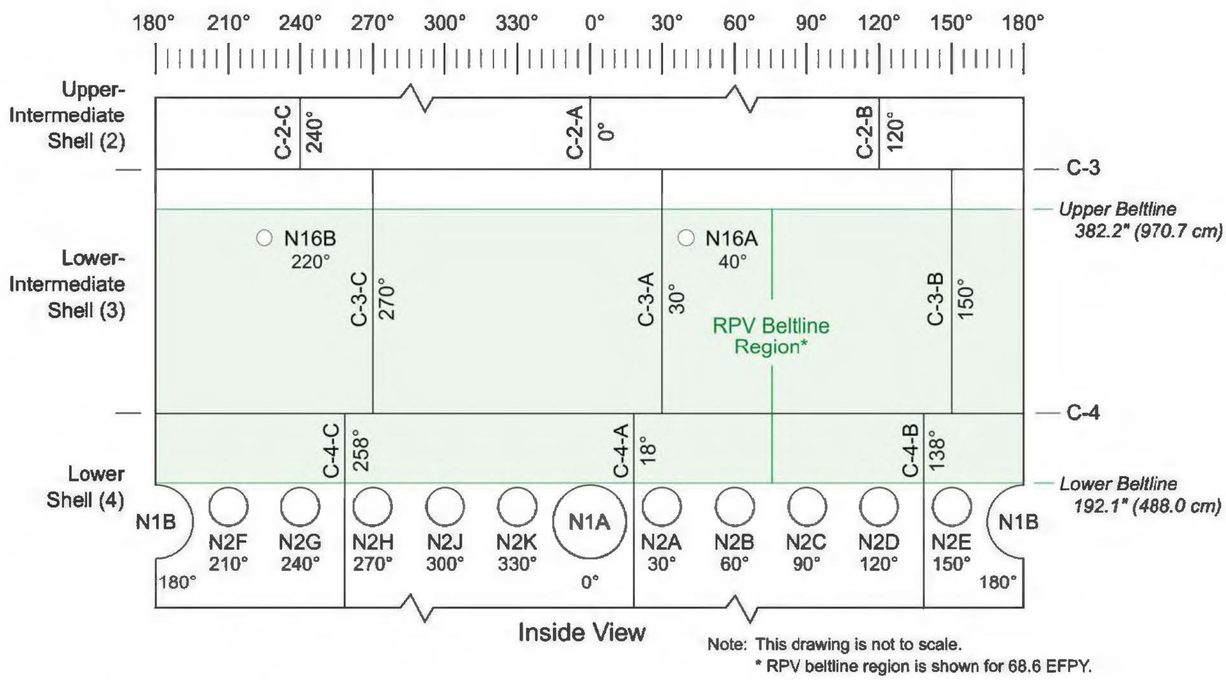


Figure 4.2.1.1-1a: Hatch Unit 1 RPV Extended Beltline Region at 68.6 EFPY

Table 4.2.1.1-1a: Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 1 RPV Extended Beltline Welds at 68.6 EFPY

Weld	Azimuth(1)	Elevation(1) [in (cm)]	Maximum Best-Estimate Fast Neutron Damage Fluence (n/cm^2)			
			0T	1/4T	3/4T	1T
Horizontal Welds						
C-3	73°	403.0 (1023.6)	2.62E+16	2.11E+16	1.59E+16	1.94E+16
C-4	48°	252.4 (641.0)	**2.96E+18**	2.10E+18	9.52E+17	5.70E+17
Shell 2 Upper-Intermediate Vertical Welds						
C-2-A	0°	403.0 (1023.6)	2.51E+16	2.03E+16	1.58E+16	1.94E+16
C-2-B	120°	403.0 (1023.6)	2.60E+16	2.10E+16	1.58E+16	1.85E+16
C-2-C	240°	403.0 (1023.6)	2.60E+16	2.10E+16	1.58E+16	1.85E+16
Shell 3 Lower-Intermediate Vertical Welds						
C-3-A	30°	303.2 (770.2)	2.32E+18	1.67E+18	7.70E+17	4.75E+17
C-3-B	150°	303.2 (770.2)	2.32E+18	1.67E+18	7.70E+17	4.75E+17
C-3-C	270°	303.2 (770.2)	1.70E+18	1.22E+18	5.66E+17	3.54E+17
Shell 4 Lower Vertical Welds						
C-4-A	18°	252.4 (641.0)	2.27E+18	1.52E+18	6.10E+17	3.53E+17
C-4-B	138°	252.4 (641.0)	2.94E+18	1.96E+18	7.77E+17	4.39E+17
C-4-C	258°	252.4 (641.0)	2.06E+18	1.38E+18	5.56E+17	3.25E+17

Notes:

(1) Azimuth and elevation values correspond to the RPV 0T location only.

Table 4.2.1.1-2a: Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 1 RPV Extended Beltline Shell Plates

Shell Plate	Azimuth(1)	Elevation(1) [in (cm)]	Maximum Best-Estimate Fast Neutron Damage Fluence (n/cm^2)			
			0T	1/4T	3/4T	1T
68.6 EFPY						
Shell 2	73°	403.0 (1023.6)	2.62E+16	2.11E+16	1.59E+16	1.94E+16
Shell 3	45°	309.2 (785.4)	**3.70E+18**	2.63E+18	1.16E+18	6.81E+17
Shell 4	48°	252.4 (641.0)	2.94E+18	1.97E+18	7.87E+17	1.94E+16

Notes:

(1) Azimuth and elevation values correspond to the RPV 0T location only.

Table 4.2.1.1-3a: Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 1 RPV N2 Nozzles in the Extended Beltline Region

Location	Azimuth(1) [Modeled (Symmetrical Locations)]	Elevation(1) [in (cm)]	Maximum Best-Estimate Fast Neutron Damage Fluence (n/cm^2)			
			0T	1/4T	3/4T	1T
N2 Nozzles at 68.6 EFPY						
Weld	30° (150°, 210°, 330°)	178.5 (453.5)	**6.45E+16**	5.15E+16	3.72E+16	4.00E+16
Extraction Path			2.07E+16	1.99E+16	2.53E+16	3.94E+16
Weld	60° (120°, 240°, 300°)		6.42E+16	5.12E+16	3.69E+16	3.97E+16
Extraction Path			2.07E+16	1.99E+16	2.52E+16	3.90E+16
Weld	90° (270°)		5.07E+16	4.07E+16	2.98E+16	3.41E+16
Extraction Path			1.59E+16	1.57E+16	2.06E+16	3.32E+16

Notes:

(1) Azimuth and elevation values correspond to their respective nozzle centerline locations.

Table 4.2.1.1-4a: Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 1 RPV N16 Nozzles in the Extended Beltline Region

Location	Azimuth(1) [Modeled (Symmetrical Locations)]	Elevation(1) [in (cm)]	Maximum Best-Estimate Fast Neutron Damage Fluence at 68.6 EFPY(n/cm^2)			
			0T	1/4T	3/4T	1T
N16 Nozzles at 68.6 EFPY						
Weld	40° (220°)	358.1 (909.6)	**8.33E+17**	6.08E+17	2.74E+17	1.83E+17

Notes:

(1) Azimuth and elevation values correspond to their respective nozzle centerline locations.

Table 4.2.1.1-5a: Reactor Pressure Vessel Beltline Elevation Range for the Hatch Unit 1 Reactor Vessel Wall

Reactor Lifetime	Lower Elevation [in (cm)]	Upper Elevation [in (cm)]	Axial Span of the RPV Beltline [in (cm)]
68.6 EFPY	192.1 (488.0)	382.2 (970.7)	190.1 (482.7)

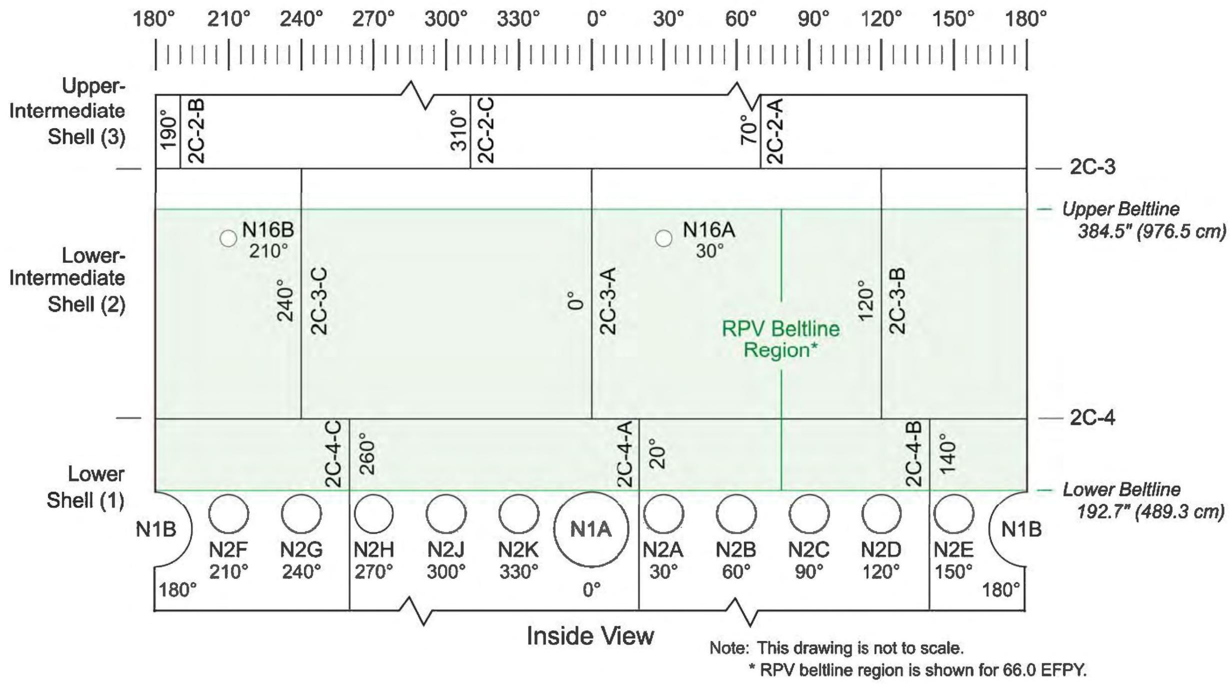


Figure 4.2.1.1-1b: Hatch Unit 2 RPV Extended Beltline Region at 66.0 EFPY

Table 4.2.1.1-1b: Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 2 RPV Extended Beltline Welds at 66.0 EFPY

Weld	Azimuth(1)	Elevation(1) [in (cm)]	Maximum Best-Estimate Fast Neutron Damage Fluence (n/cm^2)			
			0T	1/4T	3/4T	1T
Horizontal Welds						
2C-3	77°	398.6 (1012.5)	4.45E+16	3.45E+16	2.40E+16	2.62E+16
2C-4	48°	247.0 (627.4)	**2.67E+18**	1.84E+18	7.57E+17	6.55E+16
Shell 3 Upper-Intermediate Vertical Welds						
2C-2-A	70°	398.6 (1012.5)	4.40E+16	3.43E+16	2.37E+16	2.52E+16
2C-2-B	190°	398.6 (1012.5)	4.01E+16	3.19E+16	2.28E+16	2.56E+16
2C-2-C	310°	398.6 (1012.5)	4.11E+16	3.23E+16	2.31E+16	2.55E+16
Shell 2 Lower-Intermediate Vertical Welds						
2C-3-A	0°	302.9 (769.3)	2.05E+18	1.48E+18	6.83E+17	4.19E+17
2C-3-B	120°	302.9 (769.3)	2.25E+18	1.63E+18	7.53E+17	4.64E+17
2C-3-C	240°	302.9 (769.3)	2.25E+18	1.63E+18	7.53E+17	4.64E+17
Shell 1 Lower Vertical Welds						
2C-4-A	20°	247.0 (627.4)	1.99E+18	1.39E+18	5.89E+17	3.51E+17
2C-4-B	140°	247.0 (627.4)	2.56E+18	1.78E+18	7.37E+17	4.31E+17
2C-4-C	260°	247.0 (627.4)	1.74E+18	1.22E+18	5.20E+17	3.11E+17

Notes:

(1) Azimuth and elevation values correspond to the RPV 0T location only.

Table 4.2.1.1-2b: Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 2 RPV Extended Beltline Shell Plates

Shell Plate	Azimuth(1)	Elevation(1) [in (cm)]	Maximum Best-Estimate Fast Neutron Damage Fluence (n/cm^2)			
			0T	1/4T	3/4T	1T
66.0 EFPY						
Shell 1	48°	247.0 (627.4)	2.67E+18	1.84E+18	7.57E+17	5.39E+17
Shell 2	48°	313.8 (797.1)	**3.56E+18**	2.52E+18	1.12E+18	6.54E+17
Shell 3	77°	398.6 (1012.5)	4.45E+16	3.45E+16	2.40E+16	2.62E+16

Notes:

(1) Azimuth and elevation values correspond to the RPV 0T location only.

Table 4.2.1.1-3b: Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 2 RPV N2 Nozzles in the Extended Beltline Region

Location	Azimuth(1) [Modeled (Symmetrical Locations)]	Elevation(1) [in (cm)]	Maximum Best-Estimate Fast Neutron Damage Fluence (n/cm^2)			
			0T	1/4T	3/4T	1T
N2 Nozzles at 66.0 EFPY						
Weld	30° (150°, 210°, 330°)	178.5 (453.5)	**7.91E+16**	7.65E+16	4.37E+16	4.38E+16
Extraction Path			2.14E+16	2.07E+16	2.67E+16	3.62E+16
Weld	60° (120°, 240°, 300°)		7.81E+16	6.53E+16	4.58E+16	4.66E+16
Extraction Path			2.16E+16	2.08E+16	2.67E+16	3.60E+16
Weld	90° (270°)		6.30E+16	4.99E+16	3.59E+16	3.86E+16
Extraction Path			1.73E+16	1.70E+16	2.25E+16	3.18E+16

Notes:

(1) Azimuth and elevation values correspond to their respective nozzle centerline locations.

Table 4.2.1.1-4b: Maximum Best-Estimate Fast Neutron Damage Fluence for the Hatch Unit 2 RPV N16 Nozzles in the Extended Beltline Region

Location	Azimuth(1) [Modeled (Symmetrical Locations)]	Elevation(1) [in (cm)]	Maximum Best-Estimate Fast Neutron Damage Fluence at 66.0 EFPY(n/cm^2)			
			0T	1/4T	3/4T	1T
N16 Nozzles at 66.0 EFPY						
Weld	30° (210°)	358.1 (909.6)	**8.15E+17**	5.99E+17	2.93E+17	1.95E+17

Notes:

(1) Azimuth and elevation values correspond to their respective nozzle centerline locations.

Table 4.2.1.1-5b: Reactor Pressure Vessel Beltline Elevation Range for the Hatch Unit 2 Reactor Vessel Wall

Reactor Lifetime	Lower Elevation [in (cm)]	Upper Elevation [in (cm)]	Axial Span of the RPV Beltline [in (cm)]
66.0 EFPY	192.7 (489.3)	384.5 (976.5)	191.8 (487.2)

4.2.1.2 Reactor Vessel Internals (RVI) Neutron Fluence

TLAA Description

Fast neutron fluence exposure has been used as input in analyses of HNP RVI components, including the core shroud, core shroud repair tie rod, jet pump, top guide, core support plate and below core components, and core spray (CS) spargers. 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. 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-145-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 Unit 1's RVI components utilized the reactor exposure to the end of Cycle 30 (EOC 30) with fluence projections to 80 years of operation. Fluence projections for 80 years of operation are 68.6 EFPY based on the operating data for a partial-historical, partial-projection Cycle 31 and a full projection Cycle 32.

The fast neutron fluence determined for Unit 2's RVI components utilized the reactor exposure to the end of Cycle 27 (EOC 27) with fluence projections to 80 years of operation. Fluence projections for 80 years of operation are 66.0 EFPY based on the operating data for a partial-historical, partial-projection Cycle 28 comprised of GNF3 fuel products.

Maximum best-estimate fast neutron fluence (E > 1.0 MeV) is reported for the following Unit 1 and Unit 2 RVI components:

- Core Shroud:
  - The maximum fluence is reported at 0T, 1/2T, and 1T for each horizontal and vertical weld in the RPV extended beltline region: H1-H6B and V1-V11.
  - The maximum fluence is reported for the shroud head and its steam separator standpipes.
- Core Shroud Repair Tie Rod:
  - The maximum fluence is reported for the axial length of the shroud repair tie rod.
- Jet Pumps:
  - The maximum fluence is reported for the jet pump riser pipe welds: RS-1, RS-2, RS-3, RS-8, and RS-9.
  - The maximum fluence is reported for the riser pipe elbow, diffuser collar, restrainer bracket, inlet mixer nozzle, inlet mixer 180° elbow, transition piece, and replacement hold-down beam assembly(s).
- Top Guide:
  - The maximum fluence is reported for the top guide cells (grid beams).
- Core Support Plate and Below Core Components:
  - The maximum fluence and location is reported for the core support plate, 4-bundle fuel supports, single-bundle fuel supports, control rod guide tube welds/bases, instrumentation dry tubes, and core support plate rim bolts.
  - The axial fluence profile is also reported for the maximum core support plate rim bolt.
- CS Spargers:
  - The maximum fluence is reported for the CS sparger nozzles.

Table 4.2.1.2-1 provides fluence projections for the HNP-1 and HNP-2 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.2.2.3) in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.2.1.2-1: Maximum Best-Estimate Fast Neutron Fluence Projections

RVI Component		Unit 1 Maximum Best-Estimate Fast Neutron Fluence for 68.6 EFPY (n/cm^2)	Unit 2 Maximum Best-Estimate Fast Neutron Fluence for 66.0 EFPY (n/cm^2)
Core Shroud	Vertical Welds (V5, V6)	4.63E+21	4.53E+21
	Horizontal Welds (H4)	4.58E+21	4.50E+21
	Head	1.23E+19	1.57E+19
	Steam Separator Standpipes (U/1-33, U/2-35)	7.40E+18	9.50E+18
	Repair Tie Rods	1.03E+20	7.38E+19
Jet Pump Components	Weld (RS-9)	3.00E+20	2.40E+20
	Riser Pipe Elbow	1.83E+17	7.21E+17
	Diffuser Collar	7.82E+19	1.26E+20
	Restrainer Bracket	5.57E+20	6.04E+20
	Inlet Mixer Nozzle	2.94E+20	2.73E+20
	Inlet Mixer 180^o Elbow	2.40E+20	1.92E+20
	Transition Piece	2.96E+20	2.38E+20
	Hold-Down Beam	1.41E+20	1.21E+20
Top Guide Cells (Grid Beams) (cells 68, 70)		3.32E+22	3.50E+22
Core Support Plate		9.23E+20	8.77E+20
Orificed Fuel Support Piece		2.19E+21	2.21E+21
Peripheral Fuel Support Piece		6.70E+20	6.21E+20
CRGT-1 Weld		2.86E+20	3.24E+20
CRGT-2 Weld		3.34E+19	3.61E+19
CRGT-3 Weld / CRGT Base(1)		2.57E+15	6.04E+14
Instrumentation Dry Tube		1.21E+21	1.10E+21
Core Support Plate Rim Bolt		1.15E+20	1.23E+20
CS Sparger Nozzles		4.46E+19	5.73E+19

Notes:

(1) The CRGT-3 weld/base of the control rod guide tubes is below the lower extended beltline elevation. Therefore, the fluence is approximated.

4.2.2 RPV Materials Upper Shelf Energy Reduction Due to Neutron Embrittlement

TLAA Description

USE is the standard industry parameter used to indicate the maximum impact toughness of a material at high temperature. Neutron embrittlement reduces the USE value below its initial value. 10 CFR 50 Appendix G (Reference 4.8.6) requires the predicted End of Life (EOL) USE for RPV materials to be at least 50 ft-lbs. (absorbed energy) unless an approved equivalent margin analysis (EMA) supports a lower value.

The HNP Unit 1 and Unit 2 USE values were updated with fluence projections to the end of the SPEO, which is 68.6 EFPY for Unit 1 and 66 EFPY for Unit 2. The latest revision of BWRVIP-135 (Reference 4.8.7) was reviewed for any information from the EPRI BWRVIP Integrated Surveillance Program (ISP) that is applicable to HNP and is utilized in this evaluation.

Since the USE value is a function of neutron fluence which is associated with a specified operating period, the HNP USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs that require evaluation for the 80-year SPEO.

TLAA Evaluation

The predicted USE drop and EMA are calculated for all beltline materials and ISP materials with fluence using the generic attenuation method approved by the NRC in RG 1.99, using the equations in RG 1.162 (Reference 4.8.8) that accurately model the percent USE (%USE) decrease curves in RG 1.99.

The surface fluence values were calculated for HNP Unit 1 and Unit 2. However, the evaluation of USE uses the fluence values at 1/4T which are attenuated from the surface fluence values. Moreover, the final limiting %USE decrease is adjusted using the surveillance data if the capsule measured %USE decrease is higher than the RG 1.99 predicted %USE decrease.

Considering the available ISP data for HNP Unit 1 and Unit 2, a fitted USE drop is determined using RG 1.99 Position 2.2 which allows for the determination of %USE drop by plotting the reduced plant surveillance data on Figure 4.2.2-1 taken from RG 1.99 and fitting the data with a line drawn parallel to the existing lines. Where multiple surveillance data are available, the most conservative line is utilized for the %USE drop determination.

For HNP Unit 1, where some initial unirradiated USE are unavailable for beltline materials, EMA is performed for limiting USE beltline plate and weld materials. The current EMA uses the existing acceptance criteria defined in BWRVIP-74-A (Reference 4.8.9) which are the maximum allowable percent decrease in USE for the BWR/3-6 plates and BWR/2-6 welds. EMA is still required because most HNP Unit 1 materials lack unirradiated USE values, but neither the ISP plate nor matching target plate is limiting for EMA.

For HNP Unit 1, the ISP plate matches the target plate material; however, the ISP weld heat does not match the target weld material. An unirradiated USE value exists for the target plate material per the NRC's "Reactor Vessel Integrity Database Version 2.0.1" (Reference 4.8.10) but differs from the unirradiated USE of the ISP plate given by BWRVIP-135. The initial unirradiated USE values are shown in Table 4.2.2-1.

For HNP Unit 2, where initial unirradiated USE is available for all applicable materials, USE is evaluated per initial unirradiated USE values in accordance with RG 1.99 using RG 1.62 equations and the 10CFR50 acceptance criteria. The N16 instrumentation nozzle forging and weld are fabricated from non-ferritic materials which do not require impact toughness evaluation.

For HNP Unit 2, both the ISP plate and ISP weld heat do not match the target plate and weld. However, the ISP plate heat number does match the heat number for plate material used in other beltline plates. Therefore, the ISP plate data is considered if it is bounding. The unirradiated USE value for the matching plate material is provided in the

"Reactor Vessel Integrity Database Version 2.0.1" but differs from the unirradiated USE of the ISP plate given by BWRVIP-135. These initial unirradiated USE values are assigned, and the discrepancy is noted in Table 4.2.2-2. Neither the ISP plate nor the matching plate are limiting in USE. The ISP weld surveillance data are provided for information only and will not be considered because there is no matching weld heat number in the vessel beltline.

USE Evaluation with Fluence from Generic Attenuation Method

Table 4.2.2-1 lists the detailed percent drop in USE for HNP Unit 1 at 68.6 EFPY using the generic attenuated 1/4T fluence values. EMA was required for HNP Unit 1 materials because unirradiated USE values were not available for some beltline materials. It is shown that the limiting plate is the Lower Intermediate Shell #1 plate with heat number C4337-1. The limiting weld is the Lower-Intermediate Longitudinal Weld #2 with heat number IP2815. The EMA for the HNP Unit 1 limiting plate and weld are shown in Tables 4.2.2-3 and 4.2.2-4. The EMA meets the criterion set by BWRVIP-74-A.

Table 4.2.2-2 lists the detailed percent drop in USE for HNP Unit 2 at 66 EFPY using the generic attenuated 1/4T fluence values. It is shown that the limiting plate is the Lower Intermediate Shell #3 plate with heat number C8579-2 and 1/4T USE of 59.8 ft-lbs. The limiting weld is the Lower-Intermediate Longitudinal Weld with heat number 51874 and 1/4T USE of 72.4 ft-lbs. These limiting vessel materials meet the criterion set by 10 CFR 50 Appendix G.

USE Predicted Decrease from Surveillance Data

Considering the available ISP data for HNP Unit 1 and Unit 2, a fitted USE drop is determined using RG 1.99 Position 2.2 which allows for the determination of %USE drop by plotting the reduced plant surveillance data on Figure 4.2.2-1 taken from RG 1.99 and fitting the data with a line drawn parallel to the existing lines. Where multiple surveillance data are available, the most conservative line is utilized for the %USE drop determination.

The fitted %USE drop is calculated for the following HNP Unit 1 materials: the Lower Intermediate Shell #3 due to heat number match (C4114-2) with the ISP plate and the Lower Intermediate Shell #2 due to heat number match (C3985-2) with the archival heat plate. Figure 4.2.2-2 and Figure 4.2.2-3 show the fitted %USE result for these heat numbers. These results do not affect the limiting materials previously discussed.

The fitted %USE drop is calculated for the following HNP Unit 2 materials: the Lower Intermediate Shell #1 and Lower Intermediate Shell #2 due to heat number match (C8554) with the ISP plate. Figure 4.2.2-4 shows the fitted %USE result for this heat number. These results do not affect the limiting materials previously discussed.

The results demonstrate that EOL USE values for HNP Units 1 and 2 at 68.6 and 66 EFPY respectively remain bounded by the maximum allowed decrease in USE by BWRVIP-74-A or the 10 CFR 50 Appendix G criteria of at least 50 ft-lbs. through EOL. EMA evaluation is expected to remain within the limits of RG 1.99 and satisfy the margin requirements of safety against fracture, equivalent to 10 CFR 50 Appendix G requirements.

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: Hatch Unit 1 USE Assessment for 68.6 EFPY with 1/4T Fluence

	Description	ID No.	Heat No.	%Cu(2)	Unirradiated USE(1) (ft-lbs.)	1/4t Fluence(2) (n/cm^2)	% Drop in USE(3)	USE at 1/4t (ft-lbs.)	Requires EMA
Plates	Lower Shell #1	G-4805-1	C4112-1	0.13	EMA(4)	2.01E+18	15.0	-	YES
Plates	Lower Shell #2	G-4805-2	C4112-2	0.13	EMA(4)	2.01E+18	15.0	-	YES
Plates	Lower Shell #3	G-4805-3	C4149-1	0.14	EMA(4)	2.01E+18	15.7	-	YES
Plates	**Lower Intermediate Shell #1**	**G-4803-7**	**C4337-1**	**0.17**	**EMA(4)**	**2.68E+18**	**19.0**	**-**	**YES**
Plates	Lower Intermediate Shell #2 (5)	G-4804-1	C3985-2	0.13	EMA(4)	2.68E+18	16.1	-	YES
Plates	Lower Intermediate Shell #3 (6)	G-4804-2	C4114-2	0.13	88.4	2.68E+18	16.1	74.2	NO
Welds	Lower Long Weld	1-307	13253	0.221	EMA(4)	2.01E+18	24.7	-	YES
Welds	Lower-Intermediate Long. Weld #1	1-308	IP2809	0.270	EMA(4)	1.68E+18	26.9	-	YES
Welds	**Lower-Intermediate Long. Weld #2**	**1-308**	**IP2815**	**0.316**	**EMA(4)**	**1.68E+18**	**29.9**	**-**	**YES**
Welds	Lower to Lower-Intermediate Girth Weld #1	1-313	90099	0.197	EMA(4)	2.14E+18	23.4	-	YES
Welds	Lower to Lower-Intermediate Girth Weld #2	1-313	33A277	0.258	EMA(4)	2.14E+18	27.6	-	YES
Nozzles	N16 Instrumentation on Nozzle (8)	Forging & Weld	Inconel	N/A	N/A	6.03E+17	N/A	-	N/A
ISP Materials	Plate (6)	-	C4114-2	0.12	136	2.68E+18	15.4	115.1	NO
ISP Materials	Weld (7)	-	20291	0.23	110	2.14E+18	25.7	81.7	NO
ISP Materials	Archival Heat Plate (5)	-	C3985-2	0.11	112.8	2.68E+18	14.6	96.3	NO

Notes:

(1) Unirradiated USE values were not available for some beltline materials.

(2) Cu contents and 1/4T fluence values are contained in HNP calculations using RPV material data from the NRC Reactor Vessel Integrity Database (Reference 4.8.10).

(3) % Drop in USE 1/4T calculated by Equation 14 from RG 1.162:

$$D = \begin{cases} Base. & D = (100Cu + 9)(f)^{0.2368} \\ Welds. & D = (100Cu + 14)(f)^{0.2368} \\ UpperBound & D = (42.39)(f)^{0.1502} \end{cases}$$

(4) EMA for these heats is performed in accordance with BWRVIP-74-A.

(5) %USE of Lower Intermediate Shell #2 Plate as well as matching heat number Archival Heat Plate is based per RG 1.99 Position 1.2, noting discrepancy in unirradiated USE. See Figure 4.2.2-3 for the RG 1.99 Position 2 results.

(6) %USE of Lower Intermediate Shell #3 as well as matching heat number ISP Plate is based on RG 1.99 Position 1.2, noting discrepancy in unirradiated USE. See Figure 4.2.2-2 for the RG 1.99 Position 2.2 results.

(7) The ISP weld heat does not match vessel material welds.

(8) EMA USE assessment not applicable as inconel material is a non-ferritic alloy.

Table 4.2.2-2: Hatch Unit 2 USE Assessment for 66 EFPY with 1/4T Fluence

	Description	ID No.	Heat No.	%Cu(1)	Unirradiated USE (ft-lbs.)	1/4t Fluence(1) (n/cm^2)	% Drop in USE(2)	USE at 1/4t (ft-lbs.)	Requires EMA
Plates	Lower Shell #1	G-6603-1	C8553-2	0.08	95	1.82E+18	11.4	84.2	NO
	Lower Shell #2	G-6603-2	C8553-1	0.08	85	1.82E+18	11.4	75.3	NO
	Lower Shell #3	G-6603-3	C8571-1	0.08	71	1.82E+18	11.4	62.9	NO
	Lower Intermediate Shell #1(4)	G-6602-2	C8554-1	0.08	90	2.58E+18	12.3	78.9	NO
	Lower Intermediate Shell #2(4)	G-6602-1	C8554-2	0.08	93	2.58E+18	12.3	81.5	NO
	Lower Intermediate Shell #3	**G-6601-4**	**C8579-2**	**0.11**	**70**	**2.58E+18**	**14.5**	**59.8**	**NO**
Welds	Lower Long. Weld	101-842	10137	0.216	108	1.75E+18	23.5	82.6	NO
	Lower-Intermediate Long. Weld	**101-834**	**51874**	**0.147**	**89**	**1.63E+18**	**18.7**	**72.4**	**NO**
	Lower to Lower-Intermediate Girth Weld	301-871	4P6052	0.047	126	1.93E+18	12.7	110.0	NO
Nozzles	N16 Instrumentation Nozzle(6)	Forging & Weld	Inconel	N/A	N/A	5.90E+17	N/A	-	N/A
ISP Materials	Plate(4)	-	C8554	0.08	111.5	2.58E+18	12.3	97.7	NO
	Weld(5)	-	51912	0.13	120.8	1.93E+18	18.3	98.7	NO

Notes:

(1) Cu contents and 1/4T fluence values are contained in HNP calculations using RPV material data from the NRC Reactor Vessel Integrity Database (Reference 4.8.10).

(2) % Drop in USE at 1/4T calculated by Equation 14 from RG 1.162:

$$D = \begin{cases} Base, & D = (100Cu + 9)(f)^{0.2368} \\ Welds, & D = (100Cu + 14)(f)^{0.2368} \\ UpperBound, & D = (42.39)(f)^{0.1502} \end{cases}$$

(3) EMA for these heats is performed in accordance with BWRVIP-74-A.

(4) %USE of Lower Intermediate Shell #1 and Shell #2 Plate and matching heat number ISP Plate is based per RG1.99R2 Position 1.2, noting discrepancy in unirradiated USE. See Figure 4.2.2-4 for the RG 1.99 Position 2.2 results.

(5) The ISP weld heat does not match vessel material welds.
(6) EMA USE assessment not applicable as inconel material is a non-ferritic alloy.

Table 4.2.2-3: Bounding 68.6 EFPY EMA for Hatch Unit 1 Plate Material BWR/3-6 Plate

Surveillance Plate USE[1] (Heat No. C4337-1)			
Item	1st Capsule	2nd Capsule	3rd Capsule
%Cu	0.12	0.12	0.12
Capsule Fluence (n/cm^2)	2.33E+17	5.79E+17	1.38E+18
Measured % Decrease (Charpy Curves)	0.7	-3.8	-8.4
RG 1.99 Predicted % Decrease (RG 1.99, Fig. 2)	8.6	10.7	13.1
Limiting Beltline Plate USE (Heat C4337-1, Lower Shell #1):			
%Cu = 0.17			
68.6 EFPY Peak ID Fluence = 3.70E+18 n/cm^2			
68.6 EFPY 1/4T Fluence = 2.68E+18 n/cm^2			
RG 1.99 Predicted % Decrease = 19.0 (RG 1.99, Fig. 2)			
Adjusted % Decrease = N/A (RG 1.99, Position 2.2)			
Comparison of Limiting % Decrease Value to Limit			
19.0 % ≤ the maximum allowable percent USE decrease for BWR/3-6 plates, so vessel plates are bounded by EMA.			

Notes:
(1) Surveillance data correspond to plate heat number C4114-2, per BWRVIP-135, Rev. 4.

Table 4.2.2-4: Bounding 68.6 EFPY EMA for Hatch Unit 1 Plate Material BWR/2-6 Weld

Surveillance Weld USE[1] (Heat No. IP2815)				
Item	1st Capsule	2nd Capsule	3rd Capsule	4th Capsule
%Cu	0.23	0.23	0.23	0.23
Capsule Fluence (n/cm^2)	2.50E+17	3.34E+17	8.07E+17	3.29E+17
Measured % Decrease (Charpy Curves)	26.2	20.1	24.8	14.9
RG 1.99 Predicted % Decrease (RG 1.99, Fig. 2)	15.4	16.5	20.4	16.5
Limiting Beltline Weld USE (Heat IP2815, Lower-Intermediate Long. Weld #2):				
%Cu = 0.316				
68.6 EFPY Peak ID Fluence = 2.32E+18 n/cm^2				
68.6 EFPY 1/4T Fluence = 1.68E+18 n/cm^2				
RG 1.99 Predicted % Decrease = 29.9 (RG 1.99, Fig. 2)				
Adjusted % Decrease = N/A (RG 1.99, Position 2.2)				
Comparison of Limiting % Decrease Value to Limit				
29.9 % ≤ the maximum allowable percent USE decrease for BWR/2-6 welds, so vessel welds are bounded by EMA.				

Notes:

(1) Surveillance data correspond to weld heat number 20291 per BWRVIP-135, Rev. 4

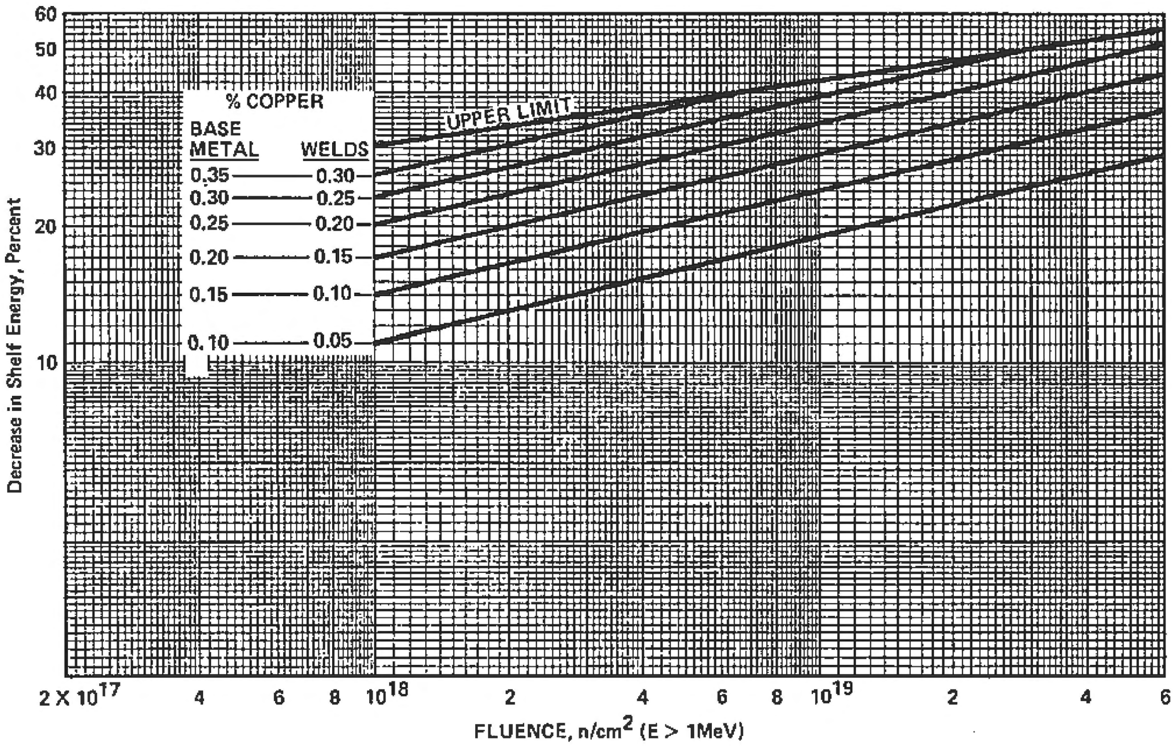


Figure 4.2.2-1: Predicted Decrease in Upper Shelf Energy as a Function of Copper Content and Fluence

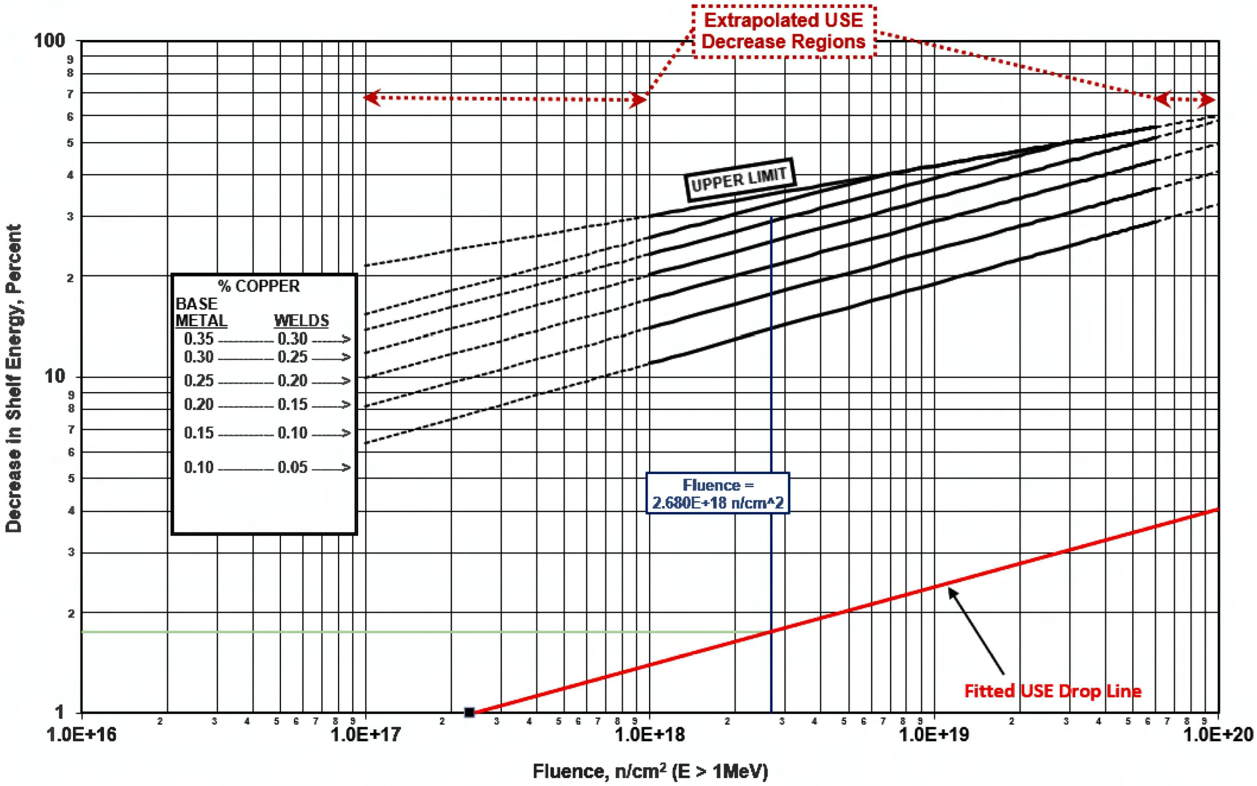


Figure 4.2.2-2: Fitted Decrease in USE for Hatch 1 Surveillance Plate Heat C4114-2

Notes:

(1) Surveillance Plate data plotted by Capsule Fluence and Measured USE Decrease from BWRVIP-135, Rev. 4 Table A-4-5. Negative values for the Measured USE Decrease are not plotted.

(2) The Measured USE Decrease for Capsule HA1 30° is 0.7 percent but is conservatively plotted at 1 percent.

(3) The placement of Fitted USE Drop Line is dictated by the data plotted by Capsule HA1 30°.

(4) The resulting Fitted USE Decrease is estimated at 1.75 percent.

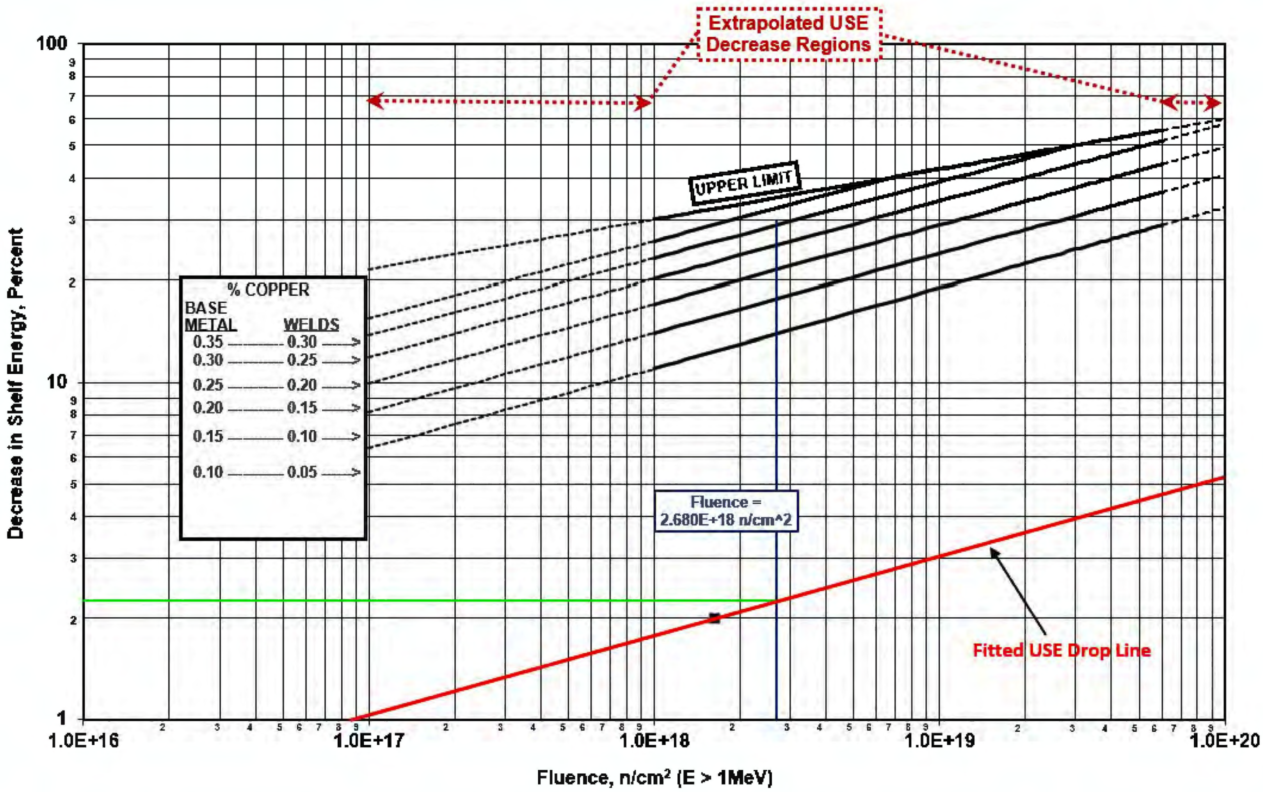


Figure 4.2.2-3: Fitted Decrease in USE for Hatch Unit 1 Archival Plate Heat C3985-2

Notes:

(1) Surveillance Plate data plotted by Capsule Fluence and Measured USE Decrease from BWRVIP-135, Rev. 4, Table A-17-5. Negative values for the Measured USE Decrease are not plotted.

(2) The placement of Fitted USE Drop Line is dictated by the data plotted by Capsule SSP H.

(3) The resulting Fitted USE Decrease is estimated at 2.25 percent.

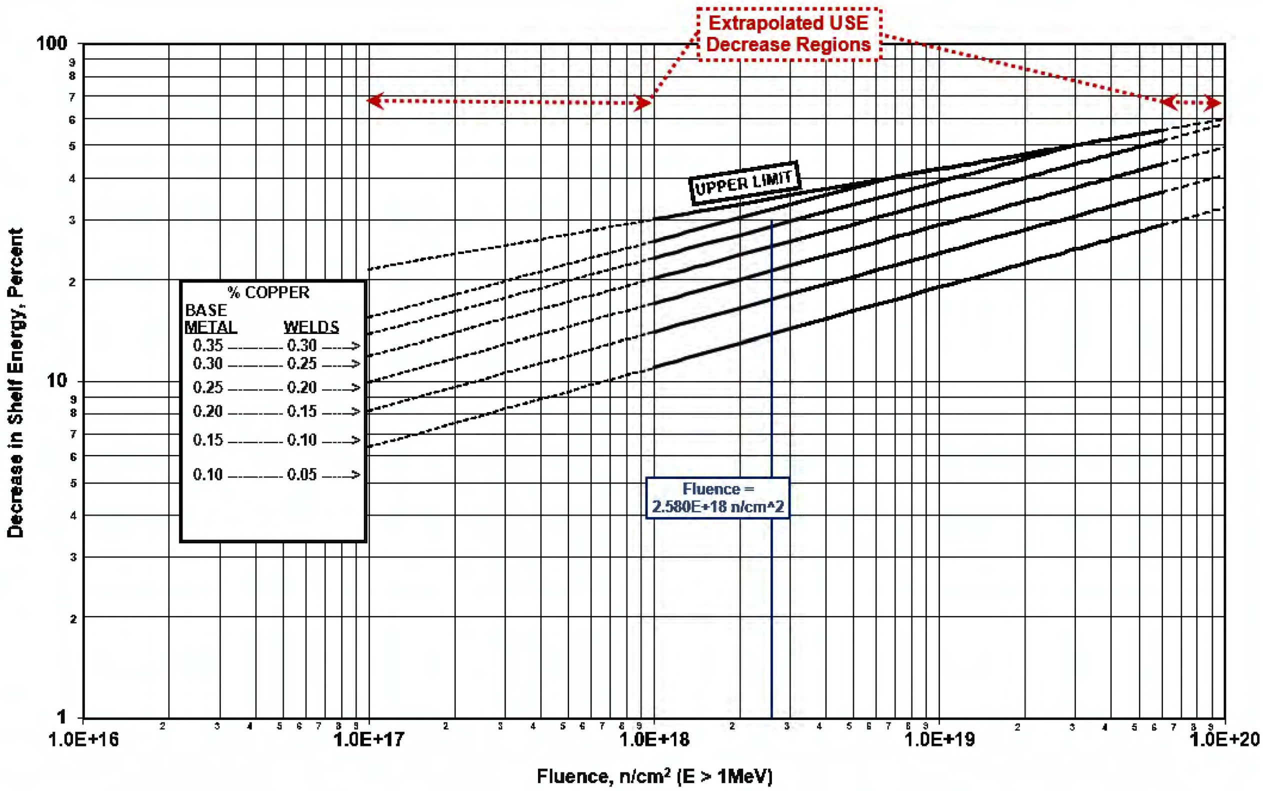


Figure 4.2.2-4: Fitted Decrease in USE for Hatch 2 Surveillance Plate Heat C8554

Notes:

(1) Surveillance Plate data plotted by Capsule Fluence and Measured USE Decrease from BWRVIP-135, Rev. 4, Table A-5-5. Negative values for the Measured USE Decrease are not plotted.

(2) All surveillance capsule data indicate negative values for Measured USE Decrease. Therefore, no Fitted USE Drop Line may be produced.

4.2.3 Adjusted Reference Temperature for RPV Materials Due to Neutron Embrittlement

TLAA Description

Radiation embrittlement of RPV materials causes a decrease in fracture toughness. The ART of the RPV 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, as required by 10 CFR Part 50, Appendix G. 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 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 by RG 1.99 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

The ART and ΔRT_{NDT} values developed for the HNP Units 1 and 2 RPV plates, welds and nozzles exposed to fluence levels greater than 1.0 x 10^{17} n/cm^2 were updated per RG 1.99. This fluence value is considered a lower bound, below which material effects due to irradiation are negligible, based on 10 CFR 50 Appendix H, Section III.A. Data from the latest BWRVIP ISP are also considered in this calculation.

Because the N16 instrumentation nozzles and welds are fabricated from non-ferritic materials Inconel SB-116 and Inconel 182, respectively, the material properties for the ART calculation are taken from the limiting adjacent base metal material. The plate heat numbers are not known relative to the position of the N16 nozzles, so the adjacent shell plate is conservatively assumed to be the shell plate with the highest chemistry factor (CF) and initial RT_{NDT} values at the nozzle location. This is appropriate because the resultant ART value will reflect the worst-case placement and will further remain bounded by the ART calculated for the shell plate itself. The limiting base metal material was found to be the Lower Intermediate Shell #1 for Unit 1 and the Lower Intermediate Shell #3 for Unit 2.

Based on the updated fluence calculations HAT-FLU-001-R-004 and HAT-FLU-001-R-002 for HNP Units 1 and 2, the reported ART and ΔRT_{NDT} values are applicable until the end of HNP's SPEO, which is 68.6 EFPY for HNP Unit 1 and 66 EFPY for HNP Unit 2.

Unit 1:

Tables 4.2.3-1, 4.2.3-2, and 4.2.3-3 provide the design inputs and the surface (0T), 1/4T, and 3/4T fluence and fluence factor (FF) values for HNP Unit 1 at 68.6 EFPY, along with the ART calculation results for 68.6 EFPY. For 68.6 EFPY, the maximum ART values computed are at the Lower to Lower- Intermediate Girth Weld #1: 0T = 152.1 °F, 1/4T = 139.3 °F, and 3/4T = 116.1 °F.

Unit 2:

Tables 4.2.3-4, 4.2.3-5, and 4.2.3-6 provide the design inputs and the surface (0T), 1/4T, and 3/4T fluence and FF values for HNP Unit 2 at 66 EFPY, along with the ART calculation results for 66 EFPY.

For 66 EFPY, the maximum ART values computed are at two different locations. For the Lower Shell #2 plate: 0T = 89.3 °F and 1/4T = 79.8 °F. Due to the influence of the change in thickness and elevated CF value, the maximum 66 EFPY ART value at 3/4T is 64.9°F computed for the Lower Intermediate Shell #3 plate.

The maximum fluence at 68.6 EFPY and 66 EFPY for Units 1 and 2, respectively, for 1/4T for each of the components listed in the tables within this section of the SLRA was calculated using the generic attenuation method as prescribed and accepted in RG 1.99, Revision 2. The surveillance material data are taken from the latest revision of BWRVIP-135. The data includes best estimate %Cu and initial unirradiated USE values of ISP materials.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The current analysis has been projected to the end of the 80-year SPEO using the 68.6 EFPY fluence for Unit 1 and 66 EFPY fluence for Unit 2. It shows that the current results for the SPEO can be used to extend the licensing basis to 80 years and meet the requirement of **10 CFR 54.21(c)(1)(ii)**.

Table 4.2.3-1: 68.6 EFPY 0T ART Values for Hatch Unit 1 RPV Materials

HATCH Unit 1 - 68.6 EFPY ART Calculation													
Description	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 0T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	σ_Δ (°F)	σ_i (°F)	Margin (°F)	ART at 0T (°F)
Plates:													
Lower Shell #1	G-4805-1	C4112-1	0.13	0.64	92.0	8	2.94E+18	0.665	61.2	17.0	0	34.0	103.2
Lower Shell #2	G-4805-2	C4112-2	0.13	0.64	92.0	10	2.94E+18	0.665	61.2	17.0	0	34.0	105.2
Lower Shell #3	G-4805-3	C4149-1	0.14	0.57	98.7	-10	2.94E+18	0.665	65.6	17.0	0	34.0	89.6
Lower Intermediate Shell #1	G-4803-7	C4337-1	0.17	0.62	127.5	-20	3.70E+18	0.725	92.5	17.0	0	34.0	106.5
Lower Intermediate Shell #2 (1)	G-4804-1	C3985-2	0.13	0.58	90.4	-20	3.70E+18	0.725	65.6	17.0	0	34.0	79.6
Lower Intermediate Shell #3 (2)	G-4804-2	C4114-2	0.13	0.70	93.5	-20	3.70E+18	0.725	67.8	17.0	0	34.0	81.8
Welds													
Lower Long. Weld	1-307	13253	0.221	0.732	189.0	-50	2.94E+18	0.665	125.7	28.0	0	56.0	131.7
Lower-Intermediate Long. Weld #1	1-308	IP2809	0.270	0.735	205.6	-50	2.32E+18	0.605	124.5	28.0	0	56.0	130.5
Lower-Intermediate Long. Weld #2	1-308	IP2815	0.316	0.724	218.6	-50	2.32E+18	0.605	132.4	28.0	0	56.0	138.4
Lower to Lower-Intermediate Girth Weld #1	**1-313**	**90099**	**0.197**	**0.600**	**159.1**	**-10**	**2.96E+18**	**0.667**	**106.1**	**28.0**	**0**	**56.0**	**152.1**
Lower to Lower-Intermediate Girth Weld #2	1-313	33A277	0.258	0.165	126.3	-50	2.96E+18	0.667	84.2	28.0	0	56.0	90.2
Nozzles													
N16 Instrumentation Nozzle	Forging & Weld	Inconel	0.17	0.62	127.5	-20	8.33E+17	0.381	48.6	17.0	0	34.0	62.6
ISP													
Integrated Surveillance Program (2)	Plate	C4114-2	0.12	0.70	175.3	-20	3.70E+18	0.725	127.1	8.5	0	17.0	124.1
Integrated Surveillance Program (3)	Weld	20291	0.23	0.75	194.5	-56	2.96E+18	0.667	129.7	28.0	17	65.5	139.2
Archival Heat Plate (1)	Plate	C3985-2	0.11	0.66	74.0	-20	3.70E+18	0.725	53.7	8.5	0	17.0	50.7

Notes:

(1) Due to the match in heat number, Lower Intermediate Shell #2 Plate ART is based per RG 1.99 R2 Position 1.1 whereas Archival Heat Plate provides ART based per RG 1.99 R2 Position 2.1.

(2) Due to the match in heat number, Lower Intermediate Shell #3 Plate ART based per RG 1.99 R2 Position 1.1 whereas ISP Plate provides ART based per RG 1.99 R2 Position 2.1.

(3) ISP weld surveillance data does not match vessel material welds.

Table 4.2.3-2: 68.6 EFPY 1/4T ART Values for Hatch Unit 1 RPV Materials

HATCH Unit 1 - 68.6 EFPY ART Calculation													
Description	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 1/4T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	σ_Δ (°F)	σ_I (°F)	Margin (°F)	ART at 1/4T (°F)
Plates:													
Lower Shell #1	G-4805-1	C4112-1	0.13	0.64	92.0	8	2.01E+18	0.570	52.4	17.0	0	34.0	94.4
Lower Shell #2	G-4805-2	C4112-2	0.13	0.64	92.0	10	2.01E+18	0.570	52.4	17.0	0	34.0	96.4
Lower Shell #3	G-4805-3	C4149-1	0.14	0.57	98.7	-10	2.01E+18	0.570	56.2	17.0	0	34.0	80.2
Lower Intermediate Shell #1	G-4803-7	C4337-1	0.17	0.62	127.5	-20	2.68E+18	0.641	81.8	17.0	0	34.0	95.8
Lower Intermediate Shell #2 (1)	G-4804-1	C3985-2	0.13	0.58	90.4	-20	2.68E+18	0.641	58.0	17.0	0	34.0	72.0
Lower Intermediate Shell #3 (2)	G-4804-2	C4114-2	0.13	0.70	93.5	-20	2.68E+18	0.641	60.0	17.0	0	34.0	74.0
Welds													
Lower Long. Weld	1-307	13253	0.221	0.732	189.0	-50	2.01E+18	0.570	107.8	28.0	0	56.0	113.8
Lower-Intermediate Long. Weld #1	1-308	IP2809	0.270	0.735	205.6	-50	1.68E+18	0.529	108.7	28.0	0	56.0	114.7
Lower-Intermediate Long. Weld #2	1-308	IP2815	0.316	0.724	218.6	-50	1.68E+18	0.529	115.6	28.0	0	56.0	121.6
Lower to Lower-Intermediate Girth Weld #1	**1-313**	**90099**	**0.197**	**0.600**	**159.1**	**-10**	**2.14E+18**	**0.586**	**93.3**	**28.0**	**0**	**56.0**	**139.3**
Lower to Lower-Intermediate Girth Weld #2	1-313	33A277	0.258	0.165	126.3	-50	2.14E+18	0.586	74.0	28.0	0	56.0	80.0
Nozzles													
N16 Instrumentation Nozzle	Forging & Weld	Inconel	0.17	0.62	127.5	-20	6.03E+17	0.323	41.2	17.0	0	34.0	55.2
ISP													
Integrated Surveillance Program (2)	Plate	C4114-2	0.12	0.70	175.3	-20	2.68E+18	0.641	112.4	8.5	0	17.0	109.4
Integrated Surveillance Program (3)	Weld	20291	0.23	0.75	194.5	-56	2.14E+18	0.586	114.0	28.0	17	65.5	123.5
Archival Heat Plate (1)	Plate	C3985-2	0.11	0.66	74.0	-20	2.68E+18	0.641	47.5	8.5	0	17.0	44.5

Notes:

(1) Due to the match in heat number, Lower Intermediate Shell #2 Plate ART is based per RG 1.99 R2 Position 1.1 whereas Archival Heat Plate provides ART based per RG 1.99 R2 Position 2.1.

(2) Due to the match in heat number, Lower Intermediate Shell #3 Plate ART based per RG 1.99 R2 Position 1.1 whereas ISP Plate provides ART based per RG 1.99 R2 Position 2.1.

(3) ISP weld surveillance data does not match vessel material welds.

Table 4.2.3-3: 68.6 EFPY 3/4T ART Values for Hatch Unit 1 RPV Materials

HATCH Unit 1 - 68.6 EFPY ART Calculation													
Description	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 3/4T (n/cm2)	Fluence Factor f	ΔRT_{NDT} (°F)	σ_Δ (°F)	σ_i (°F)	Margin (°F)	ART at 3/4T (°F)
Plates:													
Lower Shell #1	G-4805-1	C4112-1	0.13	0.64	92.0	8	9.33E+17	0.403	37.1	17.0	0	34.0	79.1
Lower Shell #2	G-4805-2	C4112-2	0.13	0.64	92.0	10	9.33E+17	0.403	37.1	17.0	0	34.0	81.1
Lower Shell #3	G-4805-3	C4149-1	0.14	0.57	98.7	-10	9.33E+17	0.403	39.8	17.0	0	34.0	63.8
Lower Intermediate Shell #1	G-4803-7	C4337-1	0.17	0.62	127.5	-20	1.41E+18	0.488	62.3	17.0	0	34.0	76.3
Lower Intermediate Shell #2 (1)	G-4804-1	C3985-2	0.13	0.58	90.4	-20	1.41E+18	0.488	44.2	17.0	0	34.0	58.2
Lower Intermediate Shell #3 (2)	G-4804-2	C4114-2	0.13	0.70	93.5	-20	1.41E+18	0.488	45.7	17.0	0	34.0	59.7
Welds													
Lower Long. Weld	1-307	13253	0.221	0.732	189.0	-50	9.33E+17	0.403	76.2	28.0	0	56.0	82.2
Lower-Intermediate Long. Weld #1	1-308	IP2809	0.270	0.735	205.6	-50	8.82E+17	0.392	80.6	28.0	0	56.0	86.6
Lower-Intermediate Long. Weld #2	1-308	IP2815	0.316	0.724	218.6	-50	8.82E+17	0.392	85.7	28.0	0	56.0	91.7
Lower to Lower-Intermediate Girth Weld #1	**1-313**	**90099**	**0.197**	**0.600**	**159.1**	**-10**	**1.12E+18**	**0.441**	**70.1**	**28.0**	**0**	**56.0**	**116.1**
Lower to Lower-Intermediate Girth Weld #2	1-313	33A277	0.258	0.165	126.3	-50	1.12E+18	0.441	55.7	27.8	0	55.7	61.3
Nozzles													
N16 Instrumentation Nozzle	Forging & Weld	Inconel	0.17	0.62	127.5	-20	3.17E+17	0.227	28.9	14.4	0	28.9	37.8
ISP													
Integrated Surveillance Program (2)	Plate	C4114-2	0.12	0.70	175.3	-20	1.41E+18	0.488	85.6	8.5	0	17.0	82.6
Integrated Surveillance Program (3)	Weld	20291	0.23	0.75	194.5	-56	1.12E+18	0.441	85.7	28.0	17	65.5	95.3
Archival Heat Plate (1)	Plate	C3985-2	0.11	0.66	74.0	-20	1.41E+18	0.488	36.1	8.5	0	17.0	33.1

Notes:

(1) Due to the match in heat number, Lower Intermediate Shell #2 Plate ART is based per RG 1.99 R2 Position 1.1 whereas Archival Heat Plate provides ART based per RG 1.99 R2 Position 2.1.

(2) Due to the match in heat number, Lower Intermediate Shell #3 Plate ART based per RG 1.99 R2 Position 1.1 whereas ISP Plate provides ART based per RG 1.99 R2 Position 2.1.

(3) ISP weld surveillance data does not match vessel material welds.

Table 4.2.3-4: 66 EFPY 0T ART Values for Hatch Unit 2 RPV Materials

HATCH Unit 2 - 66 EFPY ART Calculation													
Description	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 0T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	σ_Δ (°F)	σ_i (°F)	Margin (°F)	ART at 0T (°F)
Plates:													
Lower Shell #1	G-6603-1	C8553-2	0.08	0.58	51.0	-20	2.67E+18	0.641	32.7	16.3	0	32.7	45.3
Lower Shell #2	**G-6603-2**	**C8553-1**	**0.08**	**0.58**	**51.0**	**24**	**2.67E+18**	**0.641**	**32.7**	**16.3**	**0**	**32.7**	**89.3**
Lower Shell #3	G-6603-3	C8571-1	0.08	0.53	51.0	0	2.67E+18	0.641	32.7	16.3	0	32.7	65.3
Lower Intermediate Shell #1 (1)	G-6602-2	C8554-1	0.08	0.57	51.0	-20	3.56E+18	0.715	36.5	17.0	0	34.0	50.5
Lower Intermediate Shell #2 (1)	G-6602-1	C8554-2	0.08	0.58	51.0	-10	3.56E+18	0.715	36.5	17.0	0	34.0	60.5
Lower Intermediate Shell #3	G-6601-4	C8579-2	0.11	0.48	72.8	-4	3.56E+18	0.715	52.0	17.0	0	34.0	82.0
Welds													
Lower Long. Weld	101-842	10137	0.216	0.043	98.3	-50	2.56E+18	0.630	61.9	28.0	0	56.0	67.9
Lower-Intermediate Long. Weld	101-834	51874	0.147	0.037	67.8	-50	2.25E+18	0.598	40.6	20.3	0	40.6	31.1
Lower to Lower-Intermediate Girth Weld	301-871	4P6052	0.047	0.049	30.7	-50	2.67E+18	0.641	19.7	9.8	0	19.7	-10.6
Nozzles													
N16 Instrumentation Nozzle	Forging & Weld	Inconel	0.11	0.48	72.8	-4	8.15E+17	0.377	27.5	13.7	0	27.5	50.9
ISP													
Integrated Surveillance Program (1)	Plate	C8554	0.08	0.59	51.0	-10	3.56E+18	0.715	36.5	8.5	0	17.0	43.5
Integrated Surveillance Program (2)	Weld	51912	0.13	0.10	67.0	-56	2.67E+18	0.641	42.9	21.5	17	54.8	41.7

Notes:

(1) Due to the match in heat number, Lower Intermediate Shell #1 and Shell #2 Plate ART is based per RG 1.99 R2 Position 1.1 whereas ISP Plate provides ART based per RG 1.99 R2 Position 2.1.

(2) ISP weld surveillance data does not match vessel material welds.

Table 4.2.3-5: 66 EFPY 1/4T ART Values for Hatch Unit 2 RPV Materials

HATCH Unit 2 - 66 EFPY ART Calculation													
Description	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 1/4T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	σ_Δ (°F)	σ_i (°F)	Margin (°F)	ART at 1/4T (°F)
Plates:													
Lower Shell #1	G-6603-1	C8553-2	0.08	0.58	51.0	-20	1.82E+18	0.547	27.9	14.0	0	27.9	35.8
Lower Shell #2	**G-6603-2**	**C8553-1**	**0.08**	**0.58**	**51.0**	**24**	**1.82E+18**	**0.547**	**27.9**	**14.0**	**0**	**27.9**	**79.8**
Lower Shell #3	G-6603-3	C8571-1	0.08	0.53	51.0	0	1.82E+18	0.547	27.9	14.0	0	27.9	55.8
Lower Intermediate Shell #1 (1)	G-6602-2	C8554-1	0.08	0.57	51.0	-20	2.58E+18	0.632	32.2	16.1	0	32.2	44.4
Lower Intermediate Shell #2 (1)	G-6602-1	C8554-2	0.08	0.58	51.0	-10	2.58E+18	0.632	32.2	16.1	0	32.2	54.4
Lower Intermediate Shell #3	G-6601-4	C8579-2	0.11	0.48	72.8	-4	2.58E+18	0.632	46.0	17.0	0	34.0	76.0
Welds													
Lower Long. Weld	101-842	10137	0.216	0.043	98.3	-50	1.75E+18	0.537	52.8	26.4	0	52.8	55.7
Lower-Intermediate Long. Weld	101-834	51874	0.147	0.037	67.8	-50	1.63E+18	0.522	35.4	17.7	0	35.4	20.8
Lower to Lower-Intermediate Girth Weld	301-871	4P6052	0.047	0.049	30.7	-50	1.93E+18	0.561	17.3	8.6	0	17.3	-15.5
Nozzles													
N16 Instrumentation Nozzle	Forging & Weld	Inconel	0.11	0.48	72.8	-4	5.90E+17	0.320	23.3	11.6	0	23.3	42.6
ISP													
Integrated Surveillance Program (1)	Plate	C8554	0.08	0.59	51.0	-10	2.58E+18	0.632	32.2	8.5	0	17.0	39.2
Integrated Surveillance Program (2)	Weld	51912	0.13	0.10	67.0	-56	1.93E+18	0.561	37.6	18.8	17	50.7	32.3

Notes:

(1) Due to the match in heat number, Lower Intermediate Shell #1 and Shell #2 Plate ART is based per RG 1.99 R2 Position 1.1 whereas ISP Plate provides ART based per RG 1.99 R2 Position 2.1.

(2) ISP weld surveillance data does not match vessel material welds.

Table 4.2.3-6: 66 EFPY 3/4T ART Values for Hatch Unit 2 RPV Materials

HATCH Unit 2 - 66 EFPY ART Calculation													
Description	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 3/4T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	σ_Δ (°F)	σ_i (°F)	Margin (°F)	ART at 3/4T (°F)
Plates:													
Lower Shell #1	G-6603-1	C8553-2	0.08	0.58	51.0	-20	8.48E+17	0.385	19.6	9.8	0	19.6	19.2
Lower Shell #2	G-6603-2	C8553-1	0.08	0.58	51.0	24	8.48E+17	0.385	19.6	9.8	0	19.6	63.2
Lower Shell #3	G-6603-3	C8571-1	0.08	0.53	51.0	0	8.48E+17	0.385	19.6	9.8	0	19.6	39.2
Lower Intermediate Shell #1 (1)	G-6602-2	C8554-1	0.08	0.57	51.0	-20	1.35E+18	0.480	24.5	12.2	0	24.5	29.0
Lower Intermediate Shell #2 (1)	G-6602-1	C8554-2	0.08	0.58	51.0	-10	1.35E+18	0.480	24.5	12.2	0	24.5	39.0
Lower Intermediate Shell #3	**G-6601-4**	**C8579-2**	**0.11**	**0.48**	**72.8**	**-4**	**1.35E+18**	**0.480**	**34.9**	**17.0**	**0**	**34.0**	**64.9**
Welds													
Lower Long. Weld	101-842	10137	0.216	0.043	98.3	-50	8.13E+17	0.377	37.0	18.5	0	37.0	24.1
Lower-Intermediate Long. Weld	101-834	51874	0.147	0.037	67.8	-50	8.55E+17	0.386	26.2	13.1	0	26.2	2.4
Lower to Lower-Intermediate Girth Weld	301-871	4P6052	0.047	0.049	30.7	-50	1.01E+18	0.420	12.9	6.5	0	12.9	-24.2
Nozzles													
N16 Instrumentation Nozzle	Forging & Weld	Inconel	0.11	0.48	72.8	-4	3.10E+17	0.224	16.3	8.1	0	16.3	28.6
ISP													
Integrated Surveillance Program (1)	Plate	C8554	0.08	0.59	51.0	-10	1.35E+18	0.480	24.5	8.5	0	17.0	31.5
Integrated Surveillance Program (2)	Weld	51912	0.13	0.10	67.0	-56	1.01E+18	0.420	28.1	14.1	17	44.1	16.3

Notes:

(1) Due to the match in heat number, Lower Intermediate Shell #1 and Shell #2 Plate ART is based per RG 1.99 R2 Position 1.1 whereas ISP Plate provides ART based per RG 1.99 R2 Position 2.1.

(2) ISP weld surveillance data does not match vessel material welds.

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 in the PTLRs for both Unit 1 and Unit 2 (Reference 4.8.11). The current P-T limits are based upon fluence projections that were considered to represent HNP-1 plant operating conditions through 49.3 EFPY at the EPU power level of 2804 MWt and HNP-2 plant operating conditions through 50.1 EFPY at the EPU power level 2804 MWt. Since the P-T curves are based on 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. HNP Unit 1 and Unit 2 Technical Specification 5.6.7(c) requires that the PTLRs be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement. This ensures that the HNP Units 1 and 2 P-T limits for the SPEO will be updated prior to expiration of the P-T limits for the current periods of operation. The PTLRs are the unit specific documents that provide the operating limits relating to the:

- Reactor coolant system (RCS) pressure versus temperature limits during heatup, cooldown, and hydrostatic/Class 1 leak testing
- RCS heatup and cooldown rates
- RPV head flange boltup temperature limits

P-T limits are contained in the PTLRs, with reporting requirements in Section 5.6.7 of the HNP 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 49.3 EFPY for Unit 1 and 50.1 EFPY for Unit 2. The Technical Specification Limiting Condition for Operation (LCO) 3.4.9 states that the reactor coolant system (RCS) pressure, temperature, heatup and cooldown rates, and recirculation pump starting temperature shall be maintained within the limits specified in the PTLRs.

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 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, HNP 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.

Prior to exceeding 49.3 EFPY for Unit 1 and 50.1 EFPY for Unit 2, new P-T limit curves will be generated to cover plant operation to 68.6 EFPY for Unit 1 and 66 EFPY for Unit 2. 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 PTLR changes will be submitted to the NRC prior to exceeding the current Unit 1 49.3 EFPY and Unit 2 50.1 EFPY limits.

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 TS for HNP.

4.2.5 RPV Circumferential Weld Examination Relief

TLAA Description

BWRVIP-05 (Reference 4.8.12) 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. It also provides inspection recommendations for these welds. Section 4.6.3 of the HNP initial LRA provided a basis for use of EPRI TR-105697 (BWRVIP-05) as a technical alternative for volumetric examination through the first LR period. Generic Letter (GL) 98-05 (Reference 4.8.13) informed BWR licensees that they may request relief from the requirement to inspect circumferential welds by demonstrating that, at the expiration of their license, the circumferential welds will continue to satisfy the limiting conditional failure probability for circumferential welds in the NRC SER (Reference 4.8.14) that evaluated EPRI TR-105697 (BWRVIP-05). HNP has previously applied for and been granted relief from RPV circumferential weld inspection for the Unit 1 and the Unit 2 vessels.

Subsequently, BWRVIP-329-A-NP (Reference 4.8.15) and the associated NRC SER (Reference 4.8.16) 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-NP provides criteria for applicability based on plant-specific data.

Since the current circumferential weld failure probability analyses for HNP Units 1 and 2 are based upon fluence values associated with 60 years of operation, they have been identified as TLAAs requiring evaluation for the second period of extended operation.

TLAA Evaluation

The evaluation considered plant-specific RPV dimensions and material chemistry for HNP Unit 1 and Unit 2 for the applicability criteria in BWRVIP-329-A-NP. This confirmed that the HNP Unit 1 and Unit 2 dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A-NP. Table 4.2.5-1 provides the RPV dimensions for both HNP Units.

The limiting maximum reference temperatures (RT_{MAX}) for the Unit 1 RPV surface (0T) at 68.6 EFPY, and for the Unit 2 RPV surface (0T) at 66 EFPY, were calculated using neutron fluence, plant-specific material chemistry (copper content, nickel content, chemistry factor), and $RT_{NDT(U)}$ (referred to as initial RT_{NDT}) for the HNP plates and welds. The end-of-interval (EOI) for both HNP Units is for 80 years of operation based on 68.6 EFPY for Unit 1 and 66 EFPY for Unit 2. The 0T values were calculated for the fluence at the RPV inner surface. The EOI RT_{MAX} values for all HNP Unit 1 and Unit 2 RPV plates and welds meet the acceptability criteria for limiting plate, circumferential weld, and axial weld in BWRVIP-329-A-NP.

Although like the deterministic ART value, the RT_{MAX} criterion (as defined by BWRVIP-329-A-NP) is a probabilistic value and therefore does not include the margin term (that accounts for uncertainty in the data). As the margin is always zero or greater, the ART always conservatively bounds the RT_{MAX} value (higher values are more conservative). RT_{MAX} is the criterion for BWRVIP-329-A-NP, but ART has been included for information in the current evaluation, as ART is a commonly utilized parameter in vessel integrity assessment. The HNP Units 1 and 2 RPV material ARTs are shown in Table 4.2.5-2 and Table 4.2.5-3, respectively.

ISP data has been included directly in the evaluation as applicable to the specific vessel per ISP guidance.

Using plant-specific data for the RPV dimensions and limiting ARTs for the RPV plates and welds, the evaluation shows that the HNP Unit 1 and Unit 2 RPVs meet the applicability criteria of BWRVIP-329-A-NP. As such, on the technical basis of BWRVIP-329-A-NP and as stated in the BWRVIP-329-A-NP SER, HNP Units 1 and 2 are justified for request for alternative pursuant to 10 CFR 50.55(a)(z)(1) from the ASME Code, Section XI examinations for RPV circumferential weld for up to 80 years of plant operation (68.6 EFPY for Unit 1 and 66.0 EFPY for Unit 2).

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 50.55(a) process in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.2.5-1: RPV Dimensions for Hatch Units 1 and 2

Dimension	Hatch Unit 1 RPV Dimension (Note 1)		Within limits?	Hatch Unit 2 RPV Dimension (Note 1)		Within limits?
Reactor Vessel Inside Radius to Cladding Base Metal Interface, (in)	110.0625 (min)	110.5 (max)	Yes	110.0625 (min)	110.5 (max)	Yes
Base Metal Wall Thickness, (in)	5.375 (min)	6.375 (max)	Yes	5.375 (min)	6.375 (max)	Yes
Radius / Thickness	17.3 (min, calculated)	20.6 (max, calculated)	Yes	17.3 (min, calculated)	20.6 (max, calculated)	Yes
Cladding Thickness, (in)	0.3125 (5/16”) (nom)		Note 2	0.21875 (7/32”) (nom)		Yes

Notes:

(1) The inside radius, base metal wall thickness, and radius-to-thickness ratio for HNP are tabulated based on information from BWRVIP-329-A-NP, Table A-1. Both the plant-specific values in Table 4.2.5-1 and the values in BWRVIP-329-A-NP are within the BWRVIP-329-A-NP SER applicability limits.

(2) The cladding value of 5/16” is above the criterion of 0.310 for maximum cladding thickness within BWRVIP-329-A-NP. Through engineering judgment this value may have fewer significant figures based on the conversion from fraction to decimal. BWRVIP-329-A-NP does confirm (Chapter 5, Conclusion Number 4) that the basis evaluation bounds all domestic BWRs (including HNP Unit 1) at the time of the document’s creation. Therefore, this modification is deemed acceptable for utilization of the BWRVIP-329-A-NP evaluation.

Table 4.2.5-2: Hatch Unit 1 RPV Material Adjusted Reference Temperature for 68.6-EFPY

Parameter	Limiting Plate[1]	Limiting Circumferential Weld[1]	Limiting Axial Weld[1]
Component No.	Lower-Intermediate Shell Plate Lower Intermediate Shell #3 G-4804-2	Lower to Lower Intermediate Girth Weld #1 1-313	Lower-Intermediate Longitudinal Weld #2 1-308
Heat / Lot Identification Number	C4114-2 (Utilizing ISP Data)	90099	IP2815
Copper Content (wt. %)	0.12	0.197	0.316
Nickel Content (wt. %)	0.70	0.600	0.724
Chemistry Factor (CF) (°F)	175.3	159.1	218.6
68.6 EFPY EOI Neutron Fluence (f) (n/cm^2)	3.70 x 10^{18}	2.96 x 10^{18}	2.32 x 10^{18}
$RT_{NDT(U)}$ (°F)	-20	-10	-50
EOI ΔRT_{NDT} (°F)	127.1	106.1	132.4
EOI RT_{MAX} (°F) = $RT_{NDT(U)}$ + ΔRT_{NDT}	107.1	96.1	82.4
EOI RT_{MAX} < Limiting RT_{MAX}[2]?	Yes	Yes	Yes
Adjusted Reference Temperature (ART) (°F) = $RT_{NDT(U)}$ + ΔRT_{NDT} + Margin	124.1	152.1	138.4

Notes:

(1) Reference 4.8.10, Table 3.

(2) Limiting RT_{MAX} contained in BWRVIP-329-A.

Table 4.2.5-3: Hatch Unit 2 RPV Material Adjusted Reference Temperature for 66-EFPY

Parameter	Limiting Plate[1]	Limiting Circumferential Weld[1]	Limiting Axial Weld[1]
Component No.	Lower Shell #2 G-6603-2	Lower to Lower-Intermediate Girth Weld 301-871	Lower Longitudinal Weld 101-842
Heat / Lot Identification Number	C8553-1	4P6052	10137
Copper Content (wt. %)	0.08	0.047	0.216
Nickel Content (wt. %)	0.58	0.049	0.043
Chemistry Factor (CF) (°F)	51.0	30.7	98.3
66 EFPY EOI Neutron Fluence (f) (n/cm^2)	2.67 x 10^{18}	2.67 x 10^{18}	2.56 x 10^{18}
$RT_{NDT(U)}$ (°F)	24	-50	-50
EOI ΔRT_{NDT} (°F)	32.7	19.7	61.9
EOI RT_{MAX} (°F) = $RT_{NDT(U)}$ + ΔRT_{NDT}	56.7	-30.3	11.9
EOI RT_{MAX} < Limiting RT_{MAX}[2]?	Yes	Yes	Yes
Adjusted Reference Temperature (ART) (°F) = $RT_{NDT(U)}$ + ΔRT_{NDT} + Margin	89.3	-10.6	67.9

Notes:

(1) Reference 4.8.10, Table 6.

(2) Limiting RT_{MAX} contained in BWRVIP-329-A.

4.2.6 RPV Axial Weld Failure Probability

TLAA Description

EPRI TR-105697 (BWRVIP-05) 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. It also provides inspection recommendations for these welds. Section 4.6.3 of the HNP initial LRA provided a basis for use of EPRI TR-105697 (BWRVIP-05) as a technical alternative for volumetric examination through the first LR period.

Subsequently, BWRVIP-329-A-NP and the associated NRC SER provides 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-NP provides criteria for applicability based on plant-specific data. Since these failure probability analyses are applicable to HNP Units 1 and 2, they are TLAAs requiring evaluation through the SPEO.

TLAA Evaluation

The evaluation considered plant-specific RPV dimensions and material chemistry for HNP Unit 1 and Unit 2 for the applicability criteria in BWRVIP-329-A-NP. This confirmed that the HNP Unit 1 and Unit 2 dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A-NP. Table 4.2.5-1 provides the RPV dimensions for the HNP Units.

The limiting maximum reference temperatures (RT_{MAX}) for the Unit 1 RPV surface (0T) at 68.6 EFPY, and for the Unit 2 RPV surface (0T) at 66 EFPY, were calculated using neutron fluence, plant-specific material chemistry (copper content, nickel content, chemistry factor), and $RT_{NDT(U)}$ (referred to as initial RT_{NDT})) for the HNP plates and welds. The end-of-interval (EOI) for both HNP Units is for 80 years of operation based on 68.6 EFPY for Unit 1 and 66 EFPY for Unit 2. The 0T values were calculated for the fluence at the RPV inner surface. The EOI RT_{MAX} values for all HNP Unit 1 and Unit 2 RPV plates and welds meet the acceptability criteria for limiting plate, circumferential weld, and axial weld in BWRVIP-329-A-NP.

Although similar to the deterministic value ART, the RT_{MAX} criterion (as defined by BWRVIP-329-A-NP) is a probabilistic value and therefore does not include the margin term (that accounts for uncertainty in the data). As the margin is always zero or greater, the ART always conservatively bounds the RT_{MAX} value (higher values are more conservative). RT_{MAX} is the criterion for BWRVIP-329-A-NP, but ART has been included for information in the current evaluation, as ART is a commonly utilized parameter in vessel integrity assessment. The HNP Units 1 and 2 RPV material ARTs are shown in Table 4.2.5-2 and Table 4.2.5-3, respectively.

ISP data has been included directly in the evaluation as applicable to the specific vessel per ISP guidance.

Using plant-specific data for the RPV dimensions and limiting ARTs for the RPV plates and welds, the evaluation shows that the HNP Unit 1 and Unit 2 RPVs meet the applicability criteria of BWRVIP-329-A-NP. As such, on the technical basis of BWRVIP-329-A-NP and as stated in the BWRVIP-329-A-NP SER, HNP Units 1 and 2 are justified for acceptable technical evaluation (not regulatory relief) of embrittlement of RPV axial welds for plant operation up to 80 years (68.6 EFPY and 66 EFPY for Unit 1 and Unit 2, respectively).

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 (Section 4.2.4) and reference to generic analyses, 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 HNP Unit 2 FSAR discusses RPV thermal shock during a design basis accident (DBA) in Section A.2 in response to NRC RG 1.2 (Reference 4.8.36). The HNP FSAR cites GE Report No. NEDO-10029 (Reference 4.8.17), which concludes that no failure of the RPV due to brittle fracture because of a DBA will occur based upon the methods of fracture mechanics. This analysis is applicable to HNP Unit 1, as it is the same RPV design as HNP Unit 2.

The analysis documented in GE Report No. NEDO-10029 addresses the concern for brittle fracture of the RPV due to reflood following a postulated LOCA. The thermal shock analysis contained in this report has been accepted by the NRC as part of the licensing basis for various BWR plants (Reference 4.8.16).

The thermal shock analysis documented in GE Report No. NEDO-10029 assumed a design basis LOCA followed by a low-pressure coolant injection (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. The general irradiation effects on all locations of the RPV were not accounted for in the evaluation, and the analysis only bounded 40 years of operation.

GE report NEDO-10029 was subsequently superseded by the Ranganath paper (Reference 4.8.18) regarding RPV thermal shock and confirms that no issue occurs as a result of LOCA. The Ranganath paper's analysis for BWR-6 vessels supersedes the original analysis in GE Report No. NEDO-10029 and is applicable to the HNP vessels. The Ranganath analysis is applicable to the HNP Unit 1 and 2 BWR-4 vessels because it evaluates the bounding LOCA event, a main steam line break (MSLB), for a BWR vessel design similar to the HNP vessels' design. Although the BWR-4 and BWR-6 vessel designs are different sizes, the structural details and operating conditions are similar, and the analysis is applicable to both designs.

Based on the foregoing, thermal shock reflood of the RPV is part of the CLB for HNP. Therefore, RPV thermal shock reflood is a TLAA for SLR, defined as 80 years, or 68.6 EFPY for HNP Unit 1 and 66 EFPY for HNP Unit 2.

TLAA Evaluation

The following evaluation provides the technical basis for this issue as a TLAA for SLR, defined as 80 years or 68.6 EFPY for HNP Unit 1 and 66 EFPY for HNP Unit 2. The objective of the analyses is to demonstrate that the beltline materials in the two HNP RPVs possess sufficient margin against non-ductile failure following the design basis LOCA as required by Appendix A 10 CFR 50 GDC 31 through the end of the SPEO.

For all beltline materials, a bounding evaluation was performed in which the limiting stresses and material properties for the HNP RPVs were used. To be consistent with previous analyses, RPV integrity is assured by fracture mechanics analyses of the limiting vessel locations to show that no unstable crack propagation (of an assumed 1/4T flaw) would occur under these LOCA transient conditions for the SPEO. The limiting 0T (clad to base metal interface) ART values (utilizing the more conservative value from the generic attenuation method) for beltline materials is 152.1°F (Table 4.2.3-1) for Unit 1 and 89.3°F (Table 4.2.3-4) for Unit 2.

Crack driving force, $K_{Iapplied}$, during the transient is evaluated using the Ranganath paper, 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 4.8.19) and using the through-wall temperature distribution applicable to the limiting time steps identified in GE Report No. NEDO-10029 and the Ranganath paper. The applied loadings from the design calculations in these references are compared to the material resistance to cracking determined for the limiting beltline material in HNP at the end of the SPEO.

Main Steam Line Break:

In the Ranganath analysis, the MSLB LOCA was evaluated. Results of this analysis are summarized in Tables 4.2.7-1 and 4.2.7-2. The maximum $K_{Iapplied}$ in the vessels at any time during the transient is 105 ksi-√in, according to the analysis. Therefore, $K_{Iapplied}$ is less than the allowable value by a margin of 1.35 for both Units 1 and 2. These results demonstrate that a postulated flaw in the vessels 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 three one-dimensional models for the reactor pressure vessel. The first model utilized the BWR-6 vessel geometry and transients from the Ranganath analysis to reproduce the baseline evaluation. The other two models were based on the BWR-4 HNP Unit 1 and Unit 2 vessel geometries while applying the basis transient of the Ranganath analysis.

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. By evaluating the LOCA thermal transient shown in Figure 2 of the Ranganath analysis for both models, the applicability of the results can be evaluated accordingly for application to the HNP RPVs. Figure 4.2.7-1 shows the PIPE-TS2 thermal stress results which indicate that the BWR-6 thermal stress bounds both HNP Unit 1 and Unit 2.

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 105 ksi-√in and this maximum K_I was utilized per the Ranganath analysis. The acceptability of this K on a plant-specific basis for HNP can be determined by considering a revised allowable fracture toughness applicable to the HNP vessels for 68.6 EFPY and 66 EFPY for Units 1 and 2. Based on a 0T ART of 152.1°F and 89.3°F (for Units 1 and 2), the fracture toughness K_{IC} for (T-ART) of 256.0°F and 311.2°F (for Units 1 and 2), is above the upper shelf value of 200 ksi-√in.

The bounding stress intensity factor, K, for HNP, of 105 ksi-√in is less than the available fracture toughness of 200 ksi-√in (141 ksi-√in with safety factor) after the SPEO EFPY, which provides an acceptable result for thermal shock of the vessel due to reflood following a MSLB LOCA.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

All beltline materials in the HNP RPVs satisfy the acceptance criteria of no unstable brittle crack propagation of the assumed 1/4T flaw for postulated flaw sizes less than or equal to the flaw sizes acceptable considering operation through the end of the SPEO, 68.6 EFPY for Unit 1 and 66 EFPY for Unit 2. These analyses confirm that adequate margin against non-ductile failure of the HNP RPVs is maintained for the main steam line design basis LOCA transient through the end of the SPEO. This main steam line transient bounds the recirculation line break transient. This analysis has been projected to the end of SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

Table 4.2.7-1: Hatch Unit 1 Crack Stability Analysis for Beltline Shells during Main Steam Line Break

Item	Unit 1
Minimum vessel temperature at 1/4T (°F)	408.1
Limiting ART at 0T at 50 EFPY (°F)	152.1
T - ART (°F)	256.0
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: Hatch Unit 2 Crack Stability Analysis for Beltline Shells during Main Steam Line Break

Item	Unit 2
Minimum vessel temperature at 1/4T (°F)	400.5
Limiting ART at 0T at 62 EFPY (°F)	89.3
T - ART (°F)	311.2
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

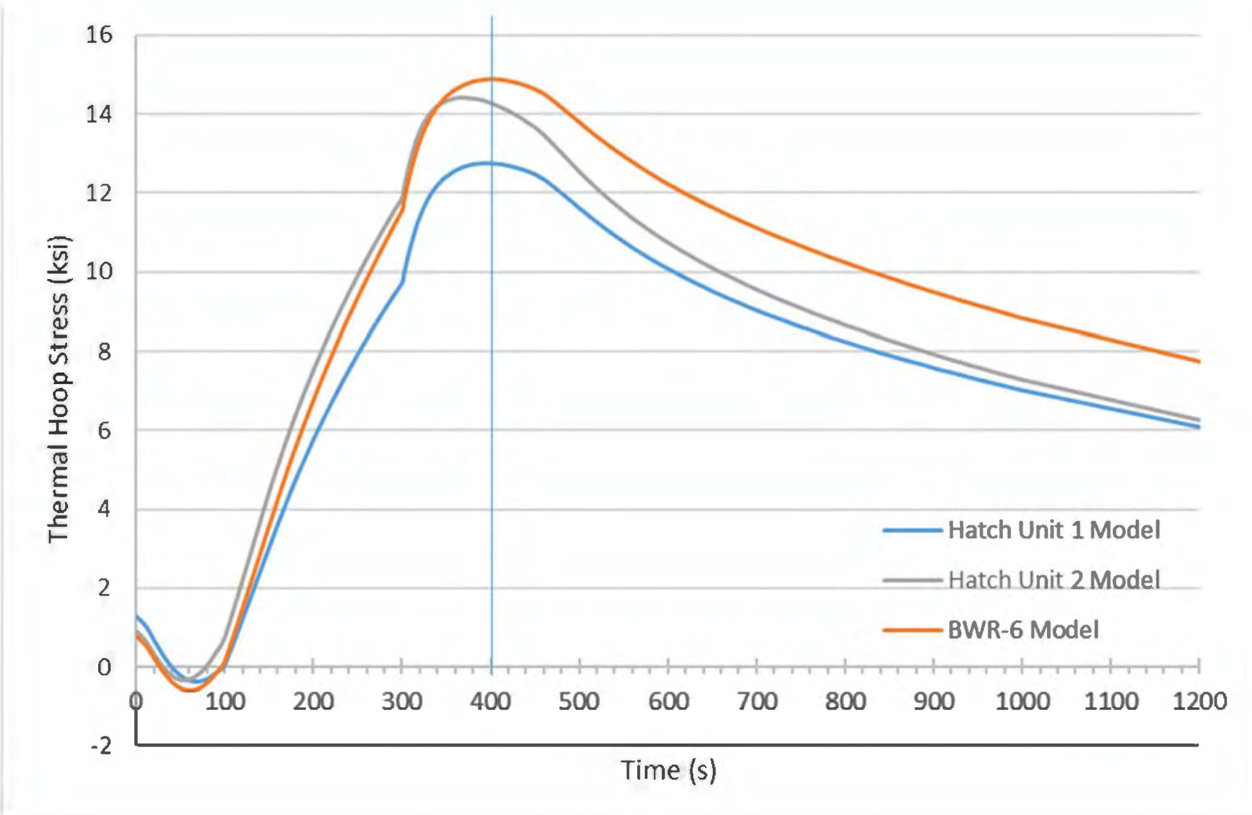


Figure 4.2.7-1: Thermal Hoop Stress over Time for the Transient from PIPE-TS2

4.2.8 Susceptibility to IASCC

TLAA Description

The occurrence of 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 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 5.0×10^{20} n/cm^2 (E > 1 MeV) is used for applicability of IASCC in BWRVIP-315 (Reference 4.8.20). 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.

HNP's LRA did not identify IASCC as a TLAA, stating that there is only a small set of near core internals that exceed the neutron fluence threshold required to render a component susceptible to IASCC. Appendix C of the LRA states that one of the conditions required for the initiation of IASCC in austenitic stainless steel reactor internals is a result of a fluence exceeding ~3-5 x 10^{20} n/cm^2 E>1.0 MeV.

IASCC requires a plant-specific aging evaluation that will evaluate the neutron fluence as an aging mechanism for the HNP austenitic stainless steel reactor internals. Because

IASCC and embrittlement are aging effects expected to occur through the SPEO, they are TLAAs that require evaluation.

TLAA Evaluation

BWRVIP-315 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 potentially susceptible to IASCC for a BWR during its SPEO that would be managed by existing guidance with clarification specific to the aging mechanism of IASCC are:

- Control rod guide tube (CRGT) assembly
- Jet pump riser, riser brace, inlet, and mixer
- Core shroud beltline cylinder
- LPCI coupling
- Top guide
- Instrument dry tubes*
- Instrument guide tubes*
- Core support plate

*Table C-1 of BWRVIP-315 concludes that dry tubes (the components listed in this line item which are exposed to significant neutron fluence) do not require augmented inspections under the BWRVIP reactor internals AMP. This conclusion is based on an assessment of the safety impact of cracking and the potential to detect dry tube leakage by means other than direct inspection of the dry tubes.

For HNP, the BWR-4 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 4.2.8-1, based on Table 4.2.1.2-1.

<u>Control Rod Guide Tube (CGRT) Assembly</u>

The maximum fluence value for the HNP CRGT assemblies is projected to be below the threshold of 5.0×10^{20} n/cm^2 through the end of the SPEO. Unit 1 maximum projected fluence is at the CRGT-1 weld, reaching 2.86×10^{20} n/cm^2. Unit 2 maximum projected fluence, also at the CRGT-1 weld, has a value of 3.24×10^{20} n/cm^2.

<u>Jet Pump Assemblies</u>

The maximum fluence for both the Unit 1 and Unit 2 HNP jet pump components is projected to exceed the threshold of 5.0×10^{20} n/cm^2 before the end of the SPEO. Therefore, the jet pump assemblies will be inspected 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 (Reference 4.8.21) is adequate to manage cracking due to

IASCC. For periodic jet pump assembly inspections, the BWR Vessel Internals AMP utilizes the recommendations provided in BWRVIP-41.

Core Shroud and Top Guide

The fluence values for both the Unit 1 and Unit 2 HNP 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. 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. The shroud is inspected and evaluated per the requirements of BWRVIP-76 (Reference 4.8.21).

Section 4.2.3 of BWRVIP-315 discusses the management of cracking due to IASCC. For periodic core shroud inspections, the BWR Vessel Internals AMP utilizes the recommendations provided in BWRVIP-76 (Reference 4.8.22). For periodic top guide inspections, the BWR Vessel Internals AMP utilizes the recommendations provided in BWRVIP-26-A (Reference 4.8.23) and BWRVIP-183NP-A (Reference 4.8.24).

Instrument Dry Tubes and Instrument Guide Tubes

Fluence values for the HNP instrument dry tubes are projected to exceed the threshold of 5.0 x 10^{20} n/cm^2 before the end of the SPEO. Although fluence values were not provided for the instrument guide tubes, this is acceptable because the dry tubes and instrument guide tubes do not require inspections. As indicated in BWRVIP-315, inspections are not required since there is no adverse safety consequence associated with failure. In addition to the conclusion in BWRVIP-315, both BWRVIP-06-A (Reference 4.8.25) and BWRVIP-47-A (Reference 4.8.26) also conclude that any failures would be detectable during normal operation by loss of monitor indications and that, regardless of such indications, failures would not impair shutdown capability.

Core Support Plate

Fluence values for the HNP core support plate are projected to exceed the threshold of 5.0 x 10^{20} n/cm^2 before the end of the SPEO. Section 4.3.1 of BWRVIP-315 discusses the Core Support Plate. There are no aging effects requiring management that are impacted by extended operation. Safety evaluation conclusions are not time dependent. Elements supporting the degradation assessment conclusions are not time dependent and are not considered a TLAA.

The aging effect of IASCC on the core shroud, top guide, and jet pump assembly components will be managed in the SPEO in accordance with the BWR Vessel Internals AMP.

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 AMP (B.2.3.7) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.2.8-1: Projected Fluence for the Associated Components

Component	Maximum Fast Neutron Fluence (n/cm^2)	
	Unit 1 – 68.6 EFPY	Unit 2 – 66.0 EFPY
Core Shroud Welds	4.63E+21	4.53E+21
Top Guide Cells	3.32E+22	3.50E+22
CRGT Assembly	2.86E+20(1)	3.24E+20(1)
Jet Pump Components	5.57E+20	6.04E+20
Core Support Plate	9.23E+20	8.77E+20
Instrument Dry Tubes(2)	1.21E+21	1.10E+21
Instrument Guide Tubes(2)	Not provided	Not provided

Notes:

(1) 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.

(2) The in-core instrumentation tube is that segment of the dry tube that resides between the fuel assemblies in the active fuel region. The in-core instrumentation guide tube is that segment of the dry tube that lies below the bottom of active fuel.

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, 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. EPU conditions are relevant for many fatigue analyses. If applicable, fatigue has been adjusted for EPU based on changes to temperature, pressure, and flow rate. This is clarified for each analysis and captures the current licensed power level. NUREG-2192 also provides examples of components likely to have fatigue TLAAs within the CLB that would require evaluation for the SPEO. Searches were performed to identify these and any other potential fatigue TLAAs within the CLB for HNP. 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 and Associated HELB Analyses (Section 4.3.6)
- Environmentally-Assisted Fatigue (Section 4.3.7)
- High Energy Line Break Analyses Based on Cumulative Fatigue Usage (Section 4.3.8)
- Cycle-dependent Fracture Mechanics or Flaw Evaluations (Section 4.3.9)

4.3.1 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.

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 Tables 4.3.1-1 and 4.3.1-2.

The most recent fatigue analysis update performed for HNP Units 1 and 2 was updated to cover plant operating history up to 12/31/2022 using the FatiguePro 3 software. The update includes cycle counts, fatigue, 60-year cycle and fatigue projections, and 80-year cycle and fatigue projections.

The event totals were revised to account for the addition of manually counted events, for events that didn’t occur or have not occurred to date, for specific events such as loss of feedwater pump and a SCRAM, and for plant shutdowns. The rate of cycle accumulation (cycles/year) and fatigue projections were calculated. The fatigue update extrapolated the most recent data over a period of 10 years, which is expected to yield the best estimate of future cycles and fatigue since it is based on the most recent plant experience.

The purpose of this section is to present the transient cycles and projections, which were used as an input to the fatigue analyses in later sections of this evaluation. Fatigue cycles are not TLAAs, as such, this section does not include a TLAA description, evaluation, or disposition discussion.

Table 4.3.1-1: Unit 1 80-Year Transient Cycle Projections

Event	Cycles as of		Projected Cycles[1]	
	12/31/2012	12/31/2022	60-year 08/06/2034	80-Year 08/06/2054
Automatic Blowdown	1	1	2	2
Boltup	33	38	45	57
Cooldown to GT 406°	223	225	241	267
Cooldown to LE 406°	253	274	309	369
DBE Earthquake	0	0	1	1
Hydrostatic Test	37	41	47	58
Hydrostatic Test 1563	3	3	4	4
Loss of Feedwater	3	4	6	8
OBE Earthquake	0	0	1	1
Partial feedwater Htr Bypass (LFWH-PBY)	33	42	53	71
RV Overpressure	0	0	1	1
RWCU Snubber Frozen	0	0	1	1
Rapid Cooldown GT 139°	4	4	5	5
Rapid Cooldown LE 139°	201	201	214	234
Rapid Heatup GT 29°	26	26	28	31
Rapid Heatup GT 42°	69	69	74	81
Rapid Heatup LE 29°	118	118	126	138
Recirc Pipe Rupture	0	0	1	1
SCRAM-All Others	264	266	284	315
SLC Initiation	0	0	1	1
SRV Blowdown	0	0	1	1
SRV Lift	248	248	263	289
Scram from Turbine Trip (SCRAM-TGT)	116	116	123	135
Shutdown	253	278	317	383
Startup	273	298	338	406
Sudden Start Recirc Pump	0	0	1	1
Turb. Trip w/o Scram (LFWH-TT)	7	9	12	16

Notes:

(1) A minimum value of 1 is applied to account for potential future events.

Table 4.3.1-2: Unit 2 80-Year Transient Cycle Projections

	Cycles as of		Projected Cycles(1)	
Event	**12/31/2012**	**12/31/2022**	**60-year 06/13/2038**	**80-Year 06/13/2058**
Boltup	29	34	43	55
Cooldown 488° to 470°	164	177	208	247
Cooldown 551° to 470°	75	80	84	94
CS Injection	0	0	1	1
Heatup/Cooldown > 100°F	599	631	723	842
Hydrostatic Test	32	37	47	58
Hydrostatic Test 1563	3	3	4	4
Improper Start Recirc Pump	0	0	1	1
Loss AC Power	0	1	3	4
OBE Earthquake	0	0	1	1
Partial feedwater Htr Bypass (LFWH-PBY)	8	18	32	49
Preop Blowdown	0	0	1	1
Rapid Cooldown > 100°/hr	145	146	160	178
Rapid Heatup > 100°/hr	114	115	127	141
Recirc Temp Cyc DT>50	426	449	515	600
Rx Coolant Pipe Rupture	0	0	1	1
SCRAM-All Others	187	187	204	225
SRV Lift	155	155	169	186
Scram from Turbine Trip (SCRAM-TGT)	15	15	17	18
Shutdown	188	201	234	276
Startup	190	203	236	278
Turb. Trip w/o Scram (LFWH-TT)	7	9	13	17

Notes:

(1) A minimum value of 1 is applied to account for potential future events.

4.3.2 ASME Section III, Class 1 Fatigue Waivers

TLAA Description

The original fatigue exemption (waiver) analyses of the HNP Unit 1 RPV exempted locations were performed to the ASME Boiler and Pressure Vessel Code, 1965 Edition with Addenda through Winter 1966. The analyses for HNP Unit 2 were performed to the 1968 Edition with Addenda through Summer 1970.

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 provides for a waiver from fatigue analysis when certain cyclic loading criteria are met.

For Unit 1, the following components were exempted from fatigue analysis:

- Vent nozzle (by comparison w/ jet pump inst. nozzle)
- 6" instrument/head spray nozzle (by comparison w/ jet pump inst. nozzle)
- Steam outlet nozzle
- 2" instrument nozzle
- Jet pump instrument nozzle
- Core differential pressure (ΔP) nozzle
- In-core instrument nozzle
- Drain nozzle
- Stabilizer bracket
- Insulation bracket (by comparison w/ stabilizer bracket)
- Head lifting lugs (by comparison w/ stabilizer bracket)
- Steam dryer hold down bracket (by comparison w/ steam dryer bracket)
- Guide rod bracket (by comparison w/ steam dryer bracket)
- Steam dryer bracket
- Feedwater sparger bracket (by comparison w/ steam dryer bracket)
- CS bracket (by comparison w/ steam dryer bracket)
- Jet pump support pads (by comparison w/ steam dryer bracket)
- Surveillance bracket (by comparison w/ steam dryer bracket)

For Unit 2, the following components were exempted from fatigue analysis:

- Vent nozzle
- 6" instrument/head spray nozzle
- 2" instrument nozzle
- Jet pump instrument nozzle
- In-core instrument nozzle
- Drain nozzle
- Stabilizer bracket
- Head lifting lugs (by comparison w/ steam dryer hold down bracket)
- Steam dryer hold down bracket
- Guide rod bracket (by comparison w/ steam dryer hold down bracket)
- Steam dryer bracket (by comparison w/ steam dryer hold down bracket)
- feedwater sparger bracket
- CS bracket
- Surveillance bracket

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 Tables 4.3.1-1 and 4.3.1-2.

Existing fatigue waiver evaluations for the head cooling spray and instrumentation nozzles and vent nozzles are described in the original RPV analysis, Combustion Engineering reports, which used a qualitative approach to show that thermal transients would not result in stresses that exceed allowable values. Several components are qualified by comparison with other components. All fatigue exemption (waiver) criteria are met for these components for 80 years. The components that bounded the head cooling spray and instrumentation nozzles and vent nozzles in the original analysis used the original design transient cycles described in SLRA Tables 4.3.2-1 and 4.3.2-2.

TLAA Evaluation

The fatigue waivers were reevaluated for 80 years in accordance with the applicable ASME Section III, Paragraph N-415-1 criteria. Pressure and temperature ranges were adjusted for EPU operating conditions. Fatigue exemption requirements require that six conditions be met from N-415.1. The re-evaluations 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

(6) Mechanical loads

Tables 4.3.2-1 and 4.3.2-2 and show the number of cycles used in the original exemption analyses, as well as 80-year projected cycles for both Unit 1 and Unit 2. Original cycles in the lower portion of the table are from the original RPV stress reports; contributing transients are derived by comparing these values with those for the individual transients. Code hydrotest is included in full pressure cycles for Unit 1 but excluded for Unit 2; each unit-specific practice is followed for 80 years.

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.

All fatigue exemption (waiver) criteria are met for the components listed above for usage for 80 years, including effects of EPU. Note that several components are qualified by comparison with other components as per the exempted component lists above. The ASME Section III Class 1 fatigue waiver acceptance criterion continues to be satisfied based on 80-year projected transient cycles through the SPEO.

Fatigue exemption includes pressure and temperature cycles due to normal operation; fatigue exemption analyses do not include emergency and faulted events. Sudden Start, Hot Standby with Drain Shutoff, and CS Injection are not part of normal operation and are faulted events. Therefore, they are not tracked in the Fatigue Monitoring AMP (B.2.2.2).

The OBE event, which has had zero occurrences in almost 50 years of HNP Unit 1 and almost 46 years of Unit 2 operations, is conservatively projected to have 1 cycle out of the analysis limit of 50 for the remaining licensed operation and throughout the SPEO. With this conservative projection of 1 OBE, there would remain a margin of 98 percent for the fatigue analysis limit. Therefore, OBE is not tracked in the Fatigue Monitoring AMP.

The stresses applied to the instrumentation nozzles and jet pump instrumentation nozzles can be conservatively assumed to be greater than the fatigue endurance limit for those components. The steam outlet nozzle is bounding for primary stress intensity. As stated in Paragraph N-451(a) Section III, ASME Code, compliance with the rules of Paragraphs N-415.1 and N-450 shows ability of nozzles to satisfy stress and cyclic life limits of Article 4 of the ASME III Code. Thus, analysis of the vent, 6” instrument/head spray, steam outlet, 2” instrument, jet pump instrument, core delta P, in-core instrument, and drain nozzles is limited to area reinforcement calculations and evaluation of primary stresses outside of the limits of reinforcement.

The ASME Code, Section III, Class 1 component fatigue waivers will be managed by the Fatigue Monitoring AMP (B.2.2.2) through the SPEO. This AMP verifies the continued acceptability of existing analyses through cycle counting and taking required actions prior to exceeding design limits that would invalidate their conclusions. Because the instrumentation nozzles and jet pump instrumentation nozzles are bounded by other locations, no additional transients are required to be monitored adequately to manage their fatigue.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The ASME Code, Section III, Class 1 component fatigue waivers will be managed by the Fatigue Monitoring AMP through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**. The Fatigue Monitoring AMP (B.2.2.2) 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: Unit 1 Transients and Number of Cycles

Transient	Number of Cycles: Unit 1 Design	Number of Cycles: Unit 1 80-Year
Design Hydrostatic Test	130	58
Start Up	120	406[4]
Loss of Feedwater Flow	10	8
Turbine Generator Trip	40	135[4]
Reactor Overpressure	1	1
Safety Valve Blowdown	2	1
All Other Scrams	147	315[4]
Improper Start of Cold Recirc Loop	5	5[1]
Sudden Start of Pump in Cold Loop	5	1
Code Hydrostatic Test	3	4[4]
Full Pressure Cycles for N-415.1(a)	253	468[4]
Significant Pressure Fluctuations for N-415.1(b)[2]	156	18
Startup/Shutdown Cycles for N-415.1(c)	120	406[4]
Significant Temperature Fluctuations for N-415.1(d), Region A	varies	18
Significant Temperature Fluctuations for N-415.1(d), Region B	varies	29
Significant Temperature Fluctuations for N-415.1(d), Region C	varies	9
Significant Temperature Fluctuations for N-415.1(e)	varies	varies
Significant Load Fluctuations for N-415.1(f)[3]	varies	1071

General Notes: Only transients that are used in the exemption analyses are included. For determining startup/shutdown cycles, shutdown cycles are bounded by startup cycles and are therefore not shown.

(1) Since this transient is not counted, design cycles are assumed for 80 years.
(2) For the original analyses, this also includes design hydrostatic test and Code hydrostatic test, which is overly conservative because they are already considered as full pressure cycles.
(3) This conservatively includes all transients considered for the steam outlet nozzle.
(4) Original transient fatigue exemption analyses were based on a presumed 40-year design life. Although the 80-year transient values exceed this, the fatigue exemption (waiver) criteria are met and remain valid through the SPEO.

Table 4.3.2-2: Unit 2 Transients and Number of Cycles

Transient	Number of Cycles Unit 2 Design	Number of Cycles Unit 2 80-Year
Design Hydrostatic Test	130	58
Start Up	120	278(4)
Turbine Roll	120	278(1) (4)
Loss of feedwater Heater, Turbine Trip	10	17(4)
Loss of Heater, Partial feedwater Heater Bypass	70	49
Turbine Generator Trip	40	18
All Other Scrams	140	225(4)
Preop Blowdown	10	1
Loss of Alternating Current (AC) Power	5	4
Full Pressure Cycles for N-415.1(a)	250	336(4)
Significant Pressure Fluctuations for N-415.1(b) (2)	335	252
Startup/Shutdown Cycles for N-415.1(c)	120	278(4)
Significant Temperature Fluctuations for N-415.1(d), Region A	varies	248
Significant Temperature Fluctuations for N-415.1(d), Region B	varies	273
Significant Temperature Fluctuations for N-415.1(d), Region C	varies	265
Significant Temperature Fluctuations for N-415.1(e)	varies	varies
Significant Load Fluctuations for N-415.1(f) (3)	varies	539

General Notes: Only transients that are used in the exemption analyses are included. For determining startup/shutdown cycles, shutdown cycles are bounded by startup cycles and are therefore not shown.

(1) Turbine roll cycles are assumed to be equal to startup cycles.
(2) For the original analyses, this also includes design hydrostatic test, which is overly conservative because it is already considered as a full pressure cycle.
(3) This conservatively includes all transients considered for the jet pump instrumentation nozzle.
(4) Original transient fatigue exemption analyses were based on a presumed 40-year design life. Although the 80-year transient values exceed this, the fatigue exemption (waiver) criteria are met and remain valid through the SPEO.

4.3.3 RPV Fatigue Analyses

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, for Class 1 design requirements:

- Unit 1 is per the 1965 edition through the winter 1966 addenda.
- Unit 2 is per the 1968 edition through the summer 1970 addenda.

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 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 HNP LRA. The 60-year evaluations now serve as the CLB and have been identified as TLAAs for the SPEO.

TLAA Evaluation

80-year fatigue projections were performed for RPV locations with identified fatigue usage. To determine whether additional locations should be monitored, screening was performed based on bounding fatigue usage values from available fatigue analyses, which are scaled for 80 years and EPU as applicable. For any location with a resulting fatigue usage greater than 1.0, a detailed fatigue analysis was performed using existing fatigue tables and 80-year cycle projections. If applicable, fatigue tables are adjusted for EPU based on changes to temperature, pressure, and flow rate.

Fatigue usage is calculated using ASME Code methodology N-415.2 or NB-3222.4(e). The fatigue waivers only consider the earlier ASME N-415.2 methodology, however, the RPV locations' fatigue analyses were performed later using the more recent ASME NB-3222.4(e) code. The allowable number of cycles (N) is determined by interpolating the fatigue curve values at the calculated alternating stress intensity (Salt).

Tables 4.3.3-1 and 4.3.3-2 list the locations screened for Units 1 and 2 along with their previous usage values and scaled usage values (80 years vs. 60 or 40) and EPU as applicable. To account for 80-years of operation, usage is multiplied by 80 and divided by the number of years analyzed as part of the CLB (40 or 60). The locations' recalculated design and 80-year fatigue usage values used in the fatigue analyses are also presented. A detailed analysis is then performed for the locations with scaled usage greater than 1.0 (shown in bold font) to recalculate the fatigue usage for 80 years. Tables 4.3.3-1 and 4.3.3-2 include both RPV and RVI locations. The RVI locations are used as a reference in Section 4.3.4 of this evaluation.

Locations with scaled usage > 1.0 are discussed below. The effects of EPU are included as required.

<u>Unit 1 Access Hole Cover Bolts (internal)</u>

The access hole cover is bolted to the shroud support plate. The previous fatigue usage of the bolts was 0.502. EPU does not impact this location because there is no change in pressure difference across the shroud support plate, which was analyzed as part of the RPV. To remove excess conservatism, S_{alt}, the alternating stress intensity, is recalculated for each load pair, resulting in a revised 80-year fatigue usage value of 0.0012, as presented in Table 4.3.3-1. This value is less than 1.0 and is therefore acceptable.

Unit 1 Instrument/Head Spray Nozzle Bolts

The previous fatigue usage of the 6" instrument/head spray nozzle bolts was 0.4. To remove excess conservatism, load pairs are separated based on stresses from the original analysis. The revised 80-year EPU fatigue usage value is recalculated as 0.1257, as presented in Table 4.3.3-1. This value is less than 1.0 and is therefore acceptable.

Unit 1 CRD Nozzles

The previous bounding fatigue usage was 0.780 at the stub tube to bottom head juncture. To remove excess conservatism, load pairs are separated based on stresses from the original analysis. The fatigue usage is recalculated based on revised inputs. The revised 80-year EPU fatigue usage value is recalculated as 0.0360, as presented in Table 4.3.3-1. This value is less than 1.0 and is therefore acceptable.

Unit 1 Shroud Support Plate

The previous bounding fatigue usage was 0.529 at the bottom surface of the plate to vessel weld. To remove excess conservatism, the zero load condition is limited and the revised 80-year EPU fatigue usage value is recalculated as 0.0439, as presented in Table 4.3.3-1. This value is less than 1.0 and is therefore acceptable.

Unit 2 Basin Seal Skirt

The previous bounding fatigue usage was 0.6769 at the flange-cylinder junction. To remove excess conservatism, S_m averaging is used as permitted by the ASME Code. The carbon steel fatigue curve in Code Case N-905 is also used to calculate EPU fatigue usage. The revised 80-year EPU fatigue usage value is recalculated as 0.6435, as presented in Table 4.3.3-2. This value is less than 1.0 and is therefore acceptable.

Unit 2 Vent Nozzle Bolts

The previous fatigue usage was 0.636. To remove excess conservatism, load pairs are separated based on stresses from the original analysis, and the fatigue usage and EPU fatigue usage are recalculated. The revised 80-year EPU fatigue usage value is recalculated as 0.5291, as presented in Table 4.3.3-2. This value is less than 1.0 and is therefore acceptable.

Unit 2 Instrument/Head Spray Nozzle Bolts

The previous fatigue usage was 0.742. To remove excess conservatism, load pairs are separated based on stresses from the original analysis. The revised 80-year EPU fatigue usage value is recalculated as 0.6462, as presented in Table 4.3.3-2. This value is less than 1.0 and is therefore acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

For all locations where usage recalculation is possible, design and 80-year projected fatigue usage is 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.2.2.2) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.3.3-1: Unit 1 Previous, Scaled, and Recalculated Fatigue Usage Values

Unit 1 Location	Previous U	Scaled U	Recalculated U_{design}	Recalculated U_{80}
Access hole cover bolts (internal)	0.502	**1.269**	0.0012	0.0012
Recirc inlet nozzle weld overlay, path 2 outside (1)(2)	0.000939	0.001	-	-
RPV head shell and flange (2)	0.083	0.166	-	-
RIN thermal sleeve, path 3 inside (1)(2)	0.009872	0.013	-	-
CRD HSR nozzle weld overlay, path 6	0.01	0.025	-	-
CRD HSR nozzle-vessel intersection (3)	0.055	0.110	-	-
Bottom head, support skirt	0.12	0.303	-	-
Vent nozzle	0.10	0.253	-	-
Vent nozzle bolts	0.35	0.885	-	-
6" instrument/head spray nozzle bolts	0.4	**1.011**	0.1210	0.1257
CS nozzle-vessel intersection	0.07	0.177	-	-
CS nozzle liner	0.11	0.278	-	-
Recirc outlet nozzle safe end	0.125	0.413	-	-
Recirc outlet nozzle bimetallic weld	0.261	0.862	-	-
CRD nozzles, stub tube-bottom head	0.780	**1.972**	0.0450	0.0360
Shroud support gusset to vessel	0.342	0.865	-	-
Shroud support plate to vessel, bottom	0.529	**1.337**	0.0286	0.0439
Basin seal skirt	0.0004	0.001	-	-

General Note: U=fatigue usage. Analyses are for 40 years and do not account for EPU unless otherwise noted. Locations with underlined usage are analyzed in detail.

(1) Analysis is for 60 years.
(2) Analysis accounts for EPU.
(3) Since the capped nozzle does not experience the analyzed nozzle transients, the analysis is bounding for EPU.

Table 4.3.3-2: Unit 2 Previous, Scaled, and Recalculated Fatigue Usage Values

Unit 2 Location	Previous U	Scaled U	Recalculated U_{design}	Recalculated U_{80}
RPV head shell and flange (2)	0.185	0.370	-	-
RIN thermal sleeve, path 3 inside (1)(2)	0.009992	0.013	-	-
Basin seal skirt	0.6769	**1.711**	0.3046	0.6435
Bottom head, support skirt	0.063	0.159	-	-
Vent nozzle bolts	0.636	**1.608**	0.3289	0.5291
6" instrument/head spray nozzle bolts	0.742	**1.876**	0.3995	0.6462
Steam outlet nozzle safe end	0.012	0.048	-	-
Steam outlet nozzle-vessel intersection	0.233	0.923	-	-
CS nozzle-vessel intersection	0.063	0.159	-	-
CRD HSR nozzle-vessel intersection (3)	0.49	0.980	-	-
Recirc outlet nozzle intersection	0.128	0.324	-	-
Core DP nozzle (cut 1, bounding)	0.274	0.693	-	-
CRD nozzles, stub tube (element 4, cut 5)	0.120	0.303	-	-
Shroud support cylinder	0.039	0.099	-	-
Bottom head at shroud support	0.133	0.336	-	-

General Note: U=fatigue usage. Analyses are for 40 years and do not account for EPU unless otherwise noted. Locations with underlined usage are analyzed in detail.

(1) Analysis is for 60 years.
(2) Analysis accounts for EPU.
(3) Since the capped nozzle does not experience the analyzed nozzle transients, the analysis is bounding for EPU.

4.3.4 Fatigue Analysis of RPV Internals

TLAA Description

As described in Section 4.3.3, the RPV 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. The original, 40-year RPV fatigue analyses were evaluated for a 60-year operating period and for EAF as part of the HNP LRA. The 60-year evaluations now serve as the CLB and have been identified as SLRA TLAAs.

The existing fatigue analyses of RPV, RVI, and RPV penetration locations were revised to incorporate 80-year transient cycle projections. The effects of EPU were included as required. Metal fatigue is a TLAA for RVI for the SPEO.

TLAA Evaluation

80-year fatigue projections were performed for RVI locations with identified fatigue usage. To determine whether additional locations should be monitored, screening was performed based on bounding fatigue usage values from available fatigue analyses, which are scaled for 80 years and EPU as applicable. For any location with a resulting fatigue usage greater than 1.0, a detailed fatigue analysis is performed using existing fatigue tables and 80-year cycle projections. If applicable, fatigue tables are adjusted for EPU based on changes to temperature, pressure, and flow rate.

Fatigue usage is calculated using ASME Boiler and Pressure Vessel Code methodology N-415.2 or NB-3222.4(e). The allowable number of cycles (N) is determined by interpolating the fatigue curve values at the calculated alternating stress intensity (S_{alt}).

The most significant Unit 1 scaled fatigue usage for the monitored RPV/RVI locations occurs at the CRD nozzles, stub tube to bottom head juncture with a scaled usage factor of 1.972. The largest Unit 2 scaled usage factor is 1.876 for the instrument/head spray nozzle bolts. These locations are bounding for all other fatigue affected components for their respective Unit.

The recalculated projected 80-year fatigue evaluation considering EPU for the bounding location is 0.0360 for the Unit 1 CRD nozzles, stub tube to bottom head juncture, and 0.6462 for the Unit 2 instrument/head spray nozzle bolts. These results are acceptable and are summarized in Tables 4.3.3-1 and 4.3.3-2.

<u>Unit 1 and Unit 2 Jet Pump Locations</u>

The detailed fatigue analyses to determine updated cumulative fatigue usage for the following RPV internals locations are documented in General Electric Hitachi (GEH) calculations. GEH performed fatigue evaluations for the Units 1 and 2 jet pump riser brace and the Unit 1 jet pump diffuser/adapter to update the CUF for the projected 80 years of operation.

80-year fatigue usage for the Units 1 and 2 jet pump riser brace along with the Unit 1 jet pump diffuser/adapter was calculated using the 1986 ASME Code Section III, Subsection NG-3222.4 methodology. Allowable cycles were determined by interpolating the 1986 ASME Section III, Appendix I fatigue curve values at the calculated alternating stress intensity. The projected 80-year design cycles calculations were determined by conservatively scaling the analysis of record values based on the design cycles to account for actual operating cycle data to date.

The analysis reviewed various transient cases for the riser braces and the diffuser/adapter. The results are as follows:

- The Unit 1 riser brace 80-year fatigue CUF = 0.786
- The Unit 2 riser brace 80-year fatigue CUF = 0.521
- The Unit 1 diffuser/adapter 80-year fatigue CUF = 0.452

The fatigue usage is less than 1.0 and is therefore acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

For all locations where usage was recalculated, the design and 80-year projected fatigue usages are less than 1.0 and are therefore acceptable. The effects of fatigue on the intended functions of the RVI will be managed by the Fatigue Monitoring AMP (B.2.2.2) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

4.3.5 ASME Section III, Class 1 Fatigue Analysis

TLAA Description

Southern Company Services (SCS), Bechtel, GE, and various subcontractors performed Class 1 component stress analyses for HNP. SCS reviewed these analyses for initial LR and identified TLAAs from the stress reports along with relevant time-dependent calculations. Thermal fatigue is addressed in most of the pipe stress analyses that were reviewed.

Class 1 piping systems were originally designed in accordance with the following ASME codes:

- Unit 1 - B31.7
- Unit 2 - Section III, NB, 1971.

ASME design codes require an evaluation of the predicted fatigue CUF for the Class 1 components. The calculation of the predicted CUF included inherent assumptions of the number of transient events over the original 40-year license term. The ASME Code requires that the Class 1 components have an initial design predicted CUF less than or equal to 1.0. Therefore, when the period of extended operation (the PEO) was considered, that Class 1 component locations with a predicted CUF of greater than 1.0 required special consideration. The CUF carries further importance in that SNC also used the predicted CUF as a screening criterion to establish locations to be monitored, inspection locations, and the location of assumed pipe breaks for accident analysis.

For the first LR, the CUF was evaluated based upon actual operating history for both HNP Units to develop a baseline for the Class 1 piping locations. The actual operating history was then used to project a 60-year CUF for each monitored location. For SLR, the existing fatigue analyses of Class I piping locations required revision to incorporate 80-year transient cycle projections, including the effects of EPU as required. Because these analyses are based on cycles postulated to occur in the 80-year design life, they are TLAAs.

TLAA Evaluation

80-year fatigue projections have been performed for all monitored locations, based on existing fatigue analysis. To determine whether additional locations should be monitored, screening was performed based on bounding fatigue usage values from available fatigue analyses, which are scaled for 80 years and EPU as applicable. For any location with a scaled 80-year fatigue usage greater than 1.0, a detailed (recalculated) fatigue analysis is performed using existing fatigue tables and 80-year cycle projections. See Tables 4.3.5-1 and 4.3.5-2. If applicable, fatigue tables are adjusted for EPU based on changes to temperature, pressure, and flow rate. Fatigue usage is calculated using B31.7/ASME Section III, 1970 Addenda, NB-3653.6(c) Code methodology for piping, as applicable for each unit.

The detailed fatigue analyses to determine updated cumulative fatigue usage for the following Class 1 component locations are documented in a plant calculation.

Unit 1 Head Vent Piping, Point 430

The previous fatigue usage of this location was 0.6029. The bounding location was re-analyzed for 80-years, accounting for EPU, and found to have an 80-year usage of 0.5382. The fatigue usage is less than 1.0 and is therefore acceptable.

Unit 1 Anchor Forging X-14, Point 3

The previous fatigue usage of this location was 0.64. The bounding location was re-analyzed for 80-years, accounting for EPU, and found to have an 80-year usage of 0.7330.

The reanalysis of this location also reduced unnecessary conservatism using a more recent ASME Section III Code instead of B31.7, which allowed for the use of S_m (allowable stress intensity) averaging and other conservatisms in calculating the allowable number of cycles. Additionally, ASME Code Case N-779 was used to reduce conservatisms.

The fatigue usage is less than 1.0 and is therefore acceptable.

Unit 2 Feedwater Pipe-to-Safe End Weld, Path 1 Outside

The previous fatigue usage of this location was 0.7553. The bounding location was re-analyzed for 80-years, accounting for EPU, and found to have an 80-year usage of 0.4374. The reanalysis of this location also reduced unnecessary conservatisms by accounting for internal OBE cycle pairing, allowing for a reduced number of OBE events in the reanalysis.

The fatigue usage is less than 1.0 and is therefore acceptable.

Unit 2 Primary Steam Condensate Drain, Point 40

The previous fatigue usage of this location was 0.4988. The bounding location was re-analyzed for 80-years, accounting for EPU, and found to have an 80-year usage of 0.9862. The reanalysis of this location reduced unnecessary conservatisms by applying S_m at the transient temperature rather than the design temperature and removing the Loss of FW Pumps, which is an emergency event.

The fatigue usage is less than 1.0 and is therefore acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

For all monitored locations, the 80-year projected fatigue usage values with EPU are less than 1.0. The fatigue analyses and corresponding CUF for HNP 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.2.2.2) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.3.5-1: Hatch Unit 1 Class 1 Piping Fatigue Usage Values

Location	Previous Fatigue Usage	Scaled Fatigue Usage	Recalculated U_{design}	Recalculated U_{80}
Discharge RHR loop A, joint 605	0.0603	0.199	-	-
RHR Suction Piping, point 282	0.0028	0.007	-	-
RHR Valve Weld Overlay, path 3 inside (1)(2)	0.063	0.084	-	-
RHR Discharge to Head Spray Flange, outside (3)	---	---	-	-
Recirc Sample System, point 145	0.0047	0.012	-	-
Head Vent Piping, point 430	0.6029	**1.524**	0.6241	0.5382
Steam Condensate Drain, point 470	0.0324	0.082	-	-
RPV Water Level Piping, calc 158, point 7	0.0055	0.014	-	-
Anchor Forging X-13, point 3	0.158	0.399	-	-
Anchor Forging X-14, point 3	0.64	**1.618**	0.2228	0.7330
Anchor Forging X-41, point 4	0.0022	0.006	-	-

General Note: U=fatigue usage; RHR=residual heat removal. Analyses are for 40 years and do not account for EPU unless otherwise noted.
U_{design} before recalculation and $U_{screening}$ are previous U and scaled U.

(1) Analysis is for 60 years.
(2) Analysis accounts for EPU.
(3) This piping has been removed.

Table 4.3.5-2: Hatch Unit 2 Class 1 Piping Fatigue Usage Values

Location	Previous Fatigue Usage	Scaled Fatigue Usage	Recalculated U_{design}	Recalculated U_{80}
Feedwater pipe-to-safe end weld, path 1 outside (1)	0.755267	**1.845**	1.3386	0.4374
Reactor head vent, point 17	0.0985	0.249	-	-
Primary steam condensate drain, point 40	0.4988	**1.261**	0.4419	0.9862
RCIC from MSIV to penetration, point 149	0.014	0.035	-	-
Instrumentation, all points	0	0	-	-
Standby liquid control, point 25	0.0032	0.008	-	-
RPV equalizer piping, point 504	0.0092	0.023	-	-
RHR return loop A, joint 602(2)	0.0963	0.193	-	-
HPCI piping from MS, point 65	0.0167	0.042	-	-
Recirc drain loop A, point 10	0.0488	0.123	-	-
MSIV leakage control line C, point 15	0.0699	0.177	-	-
RHR discharge (return) to recirc, point 50	0.3194	0.808	-	-

General Note: U=fatigue usage; RHR=residual heat removal. Analyses are for 40 years and do not account for EPU unless otherwise noted. Fatigue usage was not calculated for the shroud stabilizers. U_{design} before recalculation and $U_{screening}$ are previous U and scaled U.

(1) Analysis is for 60 years.

(2) Analysis accounts for EPU.

4.3.6 ASME Section III, Class 2 and 3 and ANSI B31.1 and Associated Line Break Analyses

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 non-Class 1 piping components designed to USAS / ANSI B31.1 and ASME Section III Code Class 2 and 3 requirements.

Although HNP's code of construction did not invoke explicit fatigue analyses for non-Class 1 piping and components, 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 stress range reduction factor (f) is 1.0 x 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. The 7,000-cycle limit is an ANSI B31.1 and ASME Section III Class 2 and 3 Code requirement for where a stress range reduction of less than 1 would need to be applied and further evaluation required.

In addition, pipe breaks for Non-ASME Class 1 high- and moderate-energy lines outside of primary containment were postulated per Atomic Energy Commission (AEC) criteria at specific locations per HNP Unit 1 FSAR Appendix N and HNP Unit 2 FSAR Supplement 15A. Some of the line break location criteria are based on stresses exceeding limits that are a function of the allowable stress (S_h) and stress range (S_A) values.

Since the allowable stress (S_h) and stress range (S_A) are a function of the stress range reduction factor for cyclic conditions, further evaluation would be necessary if the actual number of full range temperature occurrences exceeded a value of 7,000. If non-class 1 piping originally selected for line break analyses is determined to exceed 7,000 thermal occurrences, then the stress range reduction factor would have to be applied (e.g. less than 1.0) and the line break selection methodology may require the addition of new piping locations for these line break analyses.

TLAA Evaluation

Non-Class 1 piping was designed to the following codes.

Unit	Design Code	Year
1	B31.1	1967
1	B31.7 (Defers to B31.1 for Class 2 and 3)	1969
2	Section III, NC, ND	1971 through 1971 Addenda
2	B31.1	1967 through 1971 Addenda

Estimated 80-year cycles are developed based on a previously performed 80-year cycle projection for HNP Units 1 and 2, the station reactor coolant sampling procedure and conservative estimates of systems being taken out of service for required testing or maintenance.

Non-Class 1 components are excluded from the scope of this evaluation if they are in systems that may have normal/upset condition operating temperatures that do not exceed 220°F (e.g., fire protection, service water). 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 4.8.28).

The initial LR TLAA report and HNP piping & instrument diagrams (P&IDs) were used to identify affected systems for this evaluation. 80-year cycle projection information was obtained. Additionally, the station reactor coolant sampling procedure was used for 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.

Table 4.3.6-1 provides a summary of the review performed to estimate 80-year cycles. The phrase “normal operating system” is intended to help establish the basis for the number of cycles, not temperature. For normal operating systems, the full temperature range is taken as the temperature with the system in service (upper temperature) and that of the system when the plant is shutdown (lower temperature, assumed to be ambient at 70°F). Any system connected to the RPV is assumed to exceed a temperature range of 220°F, unless otherwise noted.

For initial LR an estimate of the number of thermal cycles experienced by the piping systems not analyzed to ASME Section III Class 1 requirements was performed. Table 4.3.6-1 excludes one of the systems listed in that calculation based on their maximum operating temperature (fire protection system) and added some systems that were not previously included (reactor recirculation sample piping, CS, and RWCU).

Table 4.3.6-1 was created based on more accurate projections of transient cycles used for evaluation of Class 1 systems and includes some additional conservatism as noted in the last column.

The largest number of conservatively estimated cycles in Table 4.3.6-1 (other than tubing) for 80 years is 1,864 cycles for reactor sample system piping and 1,390 cycles for the CRD hydraulic system, including scram discharge volume piping. 1,864 cycles is roughly 25 percent of the 7,000 cycles where a stress range reduction factor of less than 1.0 would need to be applied.

80-year conservatively estimated projected design cycles include 447 cycles for the feedwater system and 543 cycles for the nuclear boiler steam system. The reactor recirculation system review consisted of only the non-Class 1 piping used for reactor water sampling (see reactor sampling system, discussed in the first response above) beyond the containment isolation valve.

For tubing, non-Class 1 tubing was designed using a cookbook approach that assumed 14,000 cycles “as an element of additional conservatism.” As indicated in Table 4.3.6-1, conservatively estimated cycles for the systems not analyzed to Class 1 requirements show significant margin to the 7,000 (and 14,000) cycle values used for these piping systems and tubing lines respectively.

Consequently, the current ANSI B31.1 ASME Class 2 and Class 3 piping fatigue design criteria, and the original selection scope for line break analyses of non-Class 1 high- and moderate-energy piping 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 the conservatively estimated 1,864 full range temperature cycles for a period of 80 years based on plant operation to date. This provides a significant margin to the 7,000-cycle value which would require further evaluation. Therefore, all non-Class 1 piping systems at HNP 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	Temp Range >220°F?	Notes
Feedwater	Yes	Conservatively includes both condensate and feedwater piping. Normal operating system, so conservatively estimate full range temperature cycles as the bounding number of projected 80-year startup or shutdown cycles (Unit 1 = 406) increased by 10 percent. Total = 447
Nuclear Boiler Steam	Yes	Includes Main Steam from Main Steam Isolation Valves to the Main Turbine, Steam Line Drains, Extraction Steam, Supply to Steam Jet Air Ejectors, Condenser Hold-up Volume, etc. Normal operating system, so conservatively estimate full range temperature cycles as the bounding number of startup or shutdown cycles (Unit 1 = 406) plus partial feedwater heater bypass (Unit 1 = 71) plus turbine trip w/o Scram (Unit 2 = 17) increased by 10 percent. Total = 543

Table 4.3.6-1: Non-Class 1 Systems Evaluated

System	Temp Range >220°F?	Notes
Nuclear Boiler Steam (Reactor Pressure Relief)	Yes	Includes piping from the Safety/Relief Valves (SRVs) to the Suppression Pool. Cycles limited by the number of pressure relief operations. Conservatively estimate full range temperature cycles as the bounding number of SRV lift cycles (Unit 1 = 289) increased by 10 percent. Total = 318
Vessel Instrumentation	No	Only Class 1 instrumentation lines associated with RPV level inside containment sees higher temperatures. The temperature of the lines outside containment is below the screening temperature.
Jet Pump Instrumentation	No	Only Class 1 instrumentation lines inside containment sees higher temperatures. The temperature of the lines outside containment is below the screening temperature.
Reactor Recirculation	No	The only non-Class 1 piping is that used for reactor water sampling (see reactor sampling system) beyond the containment isolation valve for this piping.
Control Rod Drive (CRD) Hydraulic and Scram Discharge Volume	Yes	Higher temperature portion of the system includes scram discharge volume piping. Conservatively estimate full range temperature cycles as follows: • Scram time testing based on the bounding number of projected 80-year startup or shutdown cycles (Unit 1 = 406) and conservatively add 4 more Scram time tests per year (320) plus post maintenance testing estimated at twice per year for each rod (160). (Total = 886 cycles), plus • Bounding 80-year projected number of Scram-All Others (Unit 1 = 315) plus loss of feedwater (Unit 1 = 8) plus Scram from turbine trip (Unit 1 = 135) increased by 10 percent (Total = 504). Total = 1,390.
RHR	Yes	System used for containment heat removal during High Pressure Coolant Injection (HPCI) and/or Reactor Core Isolation Cooling (RCIC) operation, but temperature exceeds the screening temperature only during shutdown when RPV pressure is below system interlock pressure. Conservatively estimate full range temperature cycles as the bounding number of projected 80-year shutdown cycles (Unit 1 = 383) increased by 10 percent. Total = 421

Table 4.3.6-1: Non-Class 1 Systems Evaluated

System	Temp Range >220°F?	Notes
CS	Yes	CS is a standby system only used for periodic surveillance testing at temperatures below the screening temperature. The only time the non-Class 1 portion of the system would see temperatures above the screening temperature would be during an accident scenario. Therefore, the number of full range temperature cycles will be small and 100 is chosen as a conservative value. Total <100
HPCI	Yes (Steam only)	HPCI is a standby system used for periodic surveillance testing (typically performed quarterly [4]) as well as in response to certain scram events unless RCIC is used. Conservatively estimate full range temperature cycles as follows: • Quarterly testing and one additional test during startup every 18 months (373) plus • Post-maintenance testing twice per year (160), plus • Bounding 80-year projected number of Scram from turbine trip (Unit 1 = 135) plus loss of feedwater (Unit 1 = 8) increased by 10 percent (Total = 157). Total = 690
RCIC	Yes (Steam only)	RCIC is a standby system used for periodic surveillance testing (typically performed quarterly [4]) as well as in response to certain scram events unless HPCI is used. Conservatively estimate full range temperature cycles as follows: • Quarterly testing and one additional test during startup every 18 months (373) plus • Post-maintenance testing twice per year (160), plus • Bounding 80-year projected number of Scram from turbine trip (Unit 1 = 135) plus loss of feedwater (Unit 1 = 8) increased by 10 percent multiplied by 2 because RCIC is more likely to be used than HPCI (Total = 315). Total = 848
Standby Liquid Control (SBLC)	No	SBLC is a standby system only used in the event the CRD system is unable to provide sufficient negative reactivity to achieve reactor shutdown. The water source is below the screening temperature.
RWCU	Yes	Normal operating system required to maintain reactor water chemistry, so conservatively estimate full range temperature cycles as the bounding number of startup or shutdown cycles (Unit 1 = 406) increased by 10 percent (447) plus system out

Table 4.3.6-1: Non-Class 1 Systems Evaluated

System	Temp Range >220°F?	Notes
		of service for maintenance or system trip 4 times per year (320). Total = 797
Reactor Sample System	Yes	The station procedures associated with piping used for chemistry sampling [8] indicate that sample lines are in service taking samples from the jet pumps or RWCU unless the plant is in Modes 2-5 where RHR could be used. Core DP lines can only be used when reactor temperature is less than 212°F. This indicates they would only experience a full range temperature cycle once per operating cycle unless both the jet pump and RWCU were unavailable. Conservatively estimate full range temperature cycles as follows: • Bounding 80-year projected number of startup or shutdown cycles (Unit 1 = 406) increased by 10 percent (447) plus • Assume daily samples are required for a week following a plant trip where jet pump and RWCU are both unavailable and that this occurs once per 18-month operating cycle (373) plus • Assume an additional number of cycles that may have occurred in the past where sample lines may not have been in continuous operation (weekly sampling for 20 years = 1044) Total = 1,864

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 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” (Reference 4.8.29) 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

EAF calculations were performed for HNP Units 1 and 2 for reactor coolant pressure boundary (RCPB) locations analyzed in NUREG/CR-6260 using 80-year projected numbers of cycles. EAF calculations have been previously performed for the following applicable NUREG/CR-6260 locations:

1. Reactor vessel shell and lower head
2. Reactor vessel feedwater nozzle
3. Reactor recirculation piping (including inlet and outlet nozzles)
4. Core spray line reactor vessel nozzle and associated Class 1 piping
5. Residual heat removal (RHR) return line Class 1 piping
6. Feedwater line Class 1 piping

This EAF analysis evaluates reactor coolant pressure boundary locations utilizing the newest currently approved revision of NUREG/CR-6909, Revision 1 (Reference 4.8.30), as well as 80-year projected number of cycles in accordance with Section X.M1 of the GALL-SLR Report. Fatigue usage is calculated using ASME Code methodology except that the applicable fatigue curve from NUREG/CR-6909 Revision 1 is used instead of the ASME Code fatigue curves. The allowable number of cycles (N) is determined by interpolating the fatigue curve values at the calculated alternating stress intensity (S_{alt}). U_{en} is calculated for the above NUREG/CR-6260 locations and the additional more limiting locations analyzed for fatigue.

The environmental fatigue correction factor (F_{en}) methodology from NUREG/CR-6909 Revision 1 is used to account for the effect of the reactor water environment. 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 U_{en} = (U)(F_{en}), where U is the fatigue usage. Usage factor is also sometimes referred to as Cumulative Usage Factor (CUF).

For load set pairs that contain dynamic loading, such as operating basis earthquake (OBE), the fatigue usage caused by the dynamic portion of the strain for that load pair has a F_{en} value of 1.0. The effective F_{en} is then calculated as a weighted average of the value without dynamic loads and the value that is applicable for dynamic loads only (that is, 1.0).

For non-NUREG/CR-6260 locations, prior to screening, all locations' U_{en} values were scaled to account for an 80-year license period; that is, 40-year design usage values are multiplied by 80/40, and 60-year values are multiplied by 80/60. The resulting scaled screening value is designated $U_{en80scr}$.

Prescreening is performed on all components and piping systems for which U has been calculated during which locations with $U_{en80scr}$ less than 1.0 are removed, except for locations that were analyzed in NUREG/CR-6260 or are currently monitored. EAF screening is then performed on these remaining locations. Locations are then grouped into thermal zones, defined as a collection of piping and/or vessel locations that undergo essentially the same group of thermal and pressure transients during plant operations.

The EAF screening reviews fatigue usage information for HNP Units 1 and 2, ranks locations according to fatigue usage factors, including the effects of EAF per Revision 1 of NUREG/CR-6909, and chooses sentinel locations for further analysis or monitoring. The EAF screening approach is based on the concept of "sentinel locations" where a limited number of locations will experience the highest environmental fatigue usage. Therefore, monitoring the sentinel locations effectively manages EAF for all locations. This extends the concept that was used in NUREG/CR-6260 and adds a semi-quantitative ranking system to demonstrate that each plant component exposed to reactor coolant having a fatigue analysis can be represented by at least one sentinel location, or if the CUF_{en} value is below 1.0, does not need to be represented by a sentinel location. This ensures that EAF screening is performed on a consistent basis.

Bounding values of the environmental fatigue correction factor (F_{en}) are calculated based on location-specific dissolved oxygen (DO), maximum temperature, and other parameters. Using the resulting location-specific bounding F_{en} and fatigue usage (U), the resulting EAF usage (U_{en}) values are tabulated. (Note that not all evaluated locations require application of F_{en} due to lack of contact with reactor water).

Using bounding F_{en} values based on material type, maximum temperature, maximum sulfur content (for carbon/low alloy and stainless steel), minimum strain rate, and DO, bounding U_{en} are estimated for all locations. Bounding F_{en} is designated $F_{en80scr}$ and the resultant scaled screening value is designated $U_{en80scr}$. The bounding values were conservatively calculated using a maximum temperature of 575°F, the design temperature for both HNP Units. The sulfur content is conservatively estimated as 0.015 wt. %. DO values for each chemistry operating regime zone are used to calculate F_{en} weighted by time spent in each zone.

The EAF screening evaluation considered the following in determining thermal zones:

- Within a thermal zone, thermal shocks and thermal bending stresses vary depending only on the materials, geometry, and location of the component in the system. Therefore, the EAF screening evaluation established thermal zones based on the set of contributing design transients.
- While not all thermal zones necessarily contain multiple material types, if the thermal zone does contain multiple material types, the limiting location is determined for each material type to ensure both CUF and F_{en} values are considered in determining CUF_{en} values.
- Within each material type in a thermal zone, the location with the highest bounding CUF_{en} is selected; the location with the second highest CUF_{en} is also selected if both the top $CUF_{en} \geq 1.0$ and the top two CUF_{en} values are within a factor of 25%. Additionally, one thermal zone can screen out another thermal zone if both U and F_{en} are higher than for the thermal zone being screened out.

The sentinel locations are grouped by material type and thermal zone. They are bounding locations for monitoring and/or additional analysis. Monitoring of fatigue (and projecting actual usage) ensures fatigue usage remains below 1.0 for all locations.

Fatigue usage is calculated using USAS B31.7/ASME Code methodology except that the applicable fatigue curve from NUREG/CR-6909 Revision 1 is used in addition to the applicable ASME Code fatigue curve. ASME Code Cases N-902 and N-904 are used in the fatigue calculations to reduce excess conservatisms. Analyzed locations consist of EAF sentinel locations identified in plant specific calculations. Locations that have already been reanalyzed have been excluded.

Unit 1 and Unit 2 Recirculation Outlet Nozzles

The screening evaluation of the recirculation outlet nozzle includes both the nozzle body and adjacent piping locations. The current analysis reviews the CUFs from the previous Combustion Engineering reports which lists CUFs for the recirculation outlet nozzle's safe end, nozzle end, intersection and the bimetallic weld. The areas with the limiting usage factors are then updated for the 80-year projected usage factors for both the low alloy steel (LAS) and the stainless steel (SS) portions of the nozzle.

HNP Unit 1 has an 80-year environmental fatigue calculation update for the low alloy steel nozzle-vessel intersection and the stainless steel (assumed) bimetallic weld location. The nozzle is "A508" low alloy steel, the safe end is "SA182 F304" stainless steel and the piping is "SA240 TP304" stainless steel. The "bimetallic weld" is assumed to be a stainless steel weld. This is conservative as stainless steel environmental fatigue multipliers are higher than Inconel for the same conditions.

HNP Unit 2 has an 80-year environmental fatigue calculation update for the low alloy steel nozzle vessel intersection and the stainless steel safe end location. The vessel and nozzle are low alloy steels while the safe end is SA182 F304 stainless steel. The bimetallic weld is also conservatively assumed to be stainless steel which is the same as Unit 1's.

The recirculation inlet nozzle body is analyzed separately from the recirculation outlet nozzle body. The Unit 1 recirculation outlet nozzle body is not bounded by the recirculation inlet nozzle body's low alloy or stainless steel locations, however, it is bounded by another reactor pressure vessel nozzle body (the feedwater nozzle).

The Unit 2 recirculation outlet nozzle body is not bounded by the recirculation inlet nozzle body nor other reactor pressure vessel nozzle bodies' low alloy or stainless steel locations.

U2 recirc outlet nozzle-vessel intersection LAS $U_{en,80} = 0.9171$

U2 recirc outlet nozzle end SS $U_{en,80} = 0.0463$

U2 low alloy steel $F_{en} = 9.426$

U2 stainless steel $F_{en} = 8.505$

Loss of RWCU Flow

During the reactor water cleanup RWCU data review, several instances of loss of RWCU flow were found with significant RWCU temperature changes that might not be represented by the design transients. These transients required evaluation for their effect on fatigue usage.

Existing analyses of the RWCU piping were identified, fatigue usage values from these analyses were compiled, and a semi-quantitative calculation of fatigue usage with the loss of RWCU transient was performed. Five locations were analyzed to account for the loss of RWCU.

The defined loss of RWCU transient was compared with transients that were already analyzed for the RWCU piping to estimate the increased fatigue usage due to loss of RWCU. For RWCU inlet piping, the reactor drain piping and the piping attached to the residual heat removal (RHR) system were both analyzed to the same transients, they are considered to be in the same thermal zone for screening. RWCU outlet piping is subjected to different transients and is therefore in a different thermal zone.

The following rules were applicable to the screening:

- Locations with $U_{en80scr}$ less than 1.0 are removed.
- Within each material type in a thermal zone, the location with the highest $U_{en80scr}$ was selected.
- If not already removed, the location with the second highest $U_{en80scr}$ was also selected if the top two $U_{en80scr}$ values were within a factor of 25%.

The subject five locations, relevant calculations, analysis methodology, and results are as follows:

- Unit 1 and Unit 2 X-14 Flued Head Anchors

  Finite element modeling (FEM) was used to calculate temperature distribution in the original Unit 1 analysis and was recommended for the additional analysis. FEM was also performed for stress analysis as the same model can be used for both thermal gradient and stress analysis, thus allowing reduction in excess conservatism introduced with piping analysis rules. The Unit 2 geometry was expected to be similar to but not the same as the Unit 1 anchor. The two geometries were compared to determine if one anchor was bounding.

  An ASME Code, Section III fatigue usage analysis of the HNP Units 1 and 2 X-14 flued heads for 80 years of plant operation was performed, including the effects of EAF. The calculation used previously calculated thermal transients and unit load and determined that the bounding fatigue usage with F_{en} of Unit 1 is 0.2966 and the bounding fatigue usage with F_{en} of Unit 2 is 0.99503.

- Unit 2 Reactor Drain Point 15 and Unit 1 RCIC Piping Point 240

  The fatigue calculations for the HNP Unit 2 reactor drain point 15 and the Unit 1 RCIC point 240 were also updated. These locations were selected for additional analysis to account for loss of RWCU. The PIPESTRESS piping analysis program was used to perform the calculations. Inputs were taken from the existing analyses of these piping locations and other references as needed. The analysis adjusted the inputs for EPU, used 80-year projected cycles, added the loss of RWCU transients, and calculated the EAF. The EAF is calculated by multiplying the bounding usage for 80-year projected cycles and added transients by a bounding F_{en} value, called $F_{en80scr}$.

The Unit 1 RCIC Point 240 fatigue usage (U) is 0.0207 and the EAF usage factor (U_{en}) is 0.301. The Unit 2 reactor drain point 15 fatigue usage (U) is 0.0548 and the EAF usage factor (U_{en}) is 0.522.

- Unit 1 Reactor Drain Piping

  Class 1 analysis of the Unit 1 reactor drain piping was performed for all transients using a piping analysis program. Once completed, bounding locations were selected for additional analysis. A calculation was performed for the HNP Unit 1 reactor drain piping, which includes EAF. The PIPESTRESS piping analysis program was used to perform the calculation, accounting for EPU and 80-year projected cycles.

  The dissimilar metal weld near the RPV nozzle has the bounding fatigue usage. For the stainless steel side of the weld, the fatigue usage (U), is 0.1306, and the EAF usage factor (U_{en}) is 0.691. For the carbon steel side of the weld, the fatigue usage (U), is 0.1486, and the EAF usage factor (U_{en}) is 0.295.

Fatigue usage and EAF usage are acceptable with EPU, 80-year projected cycles, and loss of RWCU transients for the Unit 1 and Unit 2 X-14 flued head anchors, the Unit 2 reactor drain point 15, Unit 1 RCIC point 240, and the Unit 1 reactor drain piping. All of the aforementioned usage factors are projected to be less than 1.0 through the SPEO.

Table 4.3.7-1 summarizes the results of the NUREG/CR-6260 RCPB locations analyzed for 80-year projected cycles for Unit 1. As shown, no locations are projected to be above the allowable U_{en} value of 1.0 at 80 years of operation.

Table 4.3.7-2 summarizes the results of the NUREG/CR-6260 RCPB locations analyzed for 80-year projected cycles for Unit 2. As shown, no locations are projected to be above the allowable U_{en} value of 1.0 at 80 years of operation.

Tables 4.3.7-3 and 4.3.7-4 contain the previously calculated usage factors (U_{prev}), the usage factors per the applicable NUREG/CR-6909 Rev. 1 fatigue curves (U_{80}), and 80-year usage factors using the NUREG/CR-6909 Rev. 1 fatigue curves adjusted for environmental fatigue for the sentinel locations which are the bounding locations.

The fatigue analyses determined that all usages are less than 1.0 using the 80-year projected cycles and are therefore acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of EAF 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.2.2.2) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.3.7-1: Unit 1, 80-Year Projected Environmental Fatigue Summary

Component	Location	Material	$U_{en,80}$
CS Piping	Nozzle N-5B	Stainless Steel	0.8676
	Nozzle N-5B	Carbon Steel	0.9765
Recirc Piping	Point 790 (RHR Valve)	Carbon Steel	0.9392
	Point 193	Stainless Steel	0.9885
Recirc Inlet Nozzle	Nozzle Blend Radius	Low Alloy Steel	0.3051
	Nozzle-Safe End	Stainless Steel	0.0168
	Nozzle-Safe End Weld	Inconel	0.0030
Feedwater Piping	Nozzle-Piping Weld	Carbon Steel	0.2794
Feedwater Nozzle	Nozzle Blend Radius	Low Alloy Steel	0.9896
	Nozzle Safe End	Carbon Steel	0.8720
RHR Piping	Analyzed in Recirc. Piping		
Shell & Lower Head	Vessel Shell	Low Alloy Steel	0.6487
	CRD Stub Tube	Stainless Steel	0.9464
Recirc Outlet Nozzle	Nozzle-Vessel Intersection	Low Alloy Steel	0.4340
	Bimetallic Weld	Stainless Steel	0.0237
CS Nozzle	Nozzle-Vessel Intersection	Low Alloy Steel	0.1078
	Nozzle Safe End	Stainless Steel	0.3351

Table 4.3.7-2: Unit 2, 80-Year Projected Environmental Fatigue Summary

Component	Location	Material	$U_{en,80}$
CS Piping	Point 230	Carbon Steel	0.6078
Recirc Piping	Node 902	Stainless Steel	0.7019
	Node 918	Carbon Steel	0.1931
Recirc Inlet Nozzle	Nozzle Blend Radius	Low Alloy Steel	0.1074
	Nozzle-Safe End	Stainless Steel	0.0116
	Nozzle-Safe End Weld	Inconel	0.0020
Feedwater Piping	Elbow	Carbon Steel	0.0209
Feedwater Nozzle	Nozzle Blend Radius	Low Alloy Steel	0.5552
	Nozzle Safe End	Carbon Steel	0.2119
	Nozzle Safe End Weld	Inconel	0.7577
RHR Piping	Analyzed in Recirc. Piping		
Shell & Lower Head	Closure Region Shell	Low Alloy Steel	0.5985
	CRD Stub Tube	Stainless Steel	0.3393
Recirc Outlet Nozzle	Nozzle-Vessel Intersection	Low Alloy Steel	0.9171
	Nozzle End	Stainless Steel	0.0463
CS Nozzle	Nozzle-Vessel Intersection	Low Alloy Steel	0.4573
	Safe End	Low Alloy Steel	0.5951

Table 4.3.7-3: Unit 1, Sentinel Locations - Fatigue Usage Summary

Location	Material Type	U_{prev}	U_{80}	U_{en80}
Head vent piping point 430	CS	0.6029	0.5382(1)	0.569
MS line B joint 250	CS	0.51	0.0209	0.206
Equalizer system point 10, east	CS	0.3646	0.0013	0.013
Shroud support plate to vessel	LAS	0.529	0.0439(1)	0.383
Anchor X-14, point 3	SS	0.64	0.0340	0.124
Recirc drain, point 990	SS	0.1217	0.2027	0.986
Shroud support gusset to vessel	NBA	0.342	0.0834	0.240
Joint 906, RHR return loop B	CS	0.0612	0.0752	0.695
Joint 605, RHR return loop A	CS	0.0603	0.0742	0.686
Joint 193, RHR tee loop B	SS	0.0596	0.3026	0.873
RHR discharge point 254	CS	0.2252	0.4053	0.953
RHR discharge point 290	CS	0.2114	(2)	(2)
SLC piping point 186	SS	0.2183	0.2241	0.531
SLC piping point 188	SS	0.2101	(3)	(3)

General notes:
(1) Based on ASME Code fatigue curve.
(2) Per plant calculations, this point will always be bounded by point 254 and need not be monitored.
(3) Per plant calculations, this point will always be bounded by point 186 and need not be monitored.

- MS=main steam; RHR=residual heat removal; SLC=standby liquid control; NBA=nickel-based alloy.
- U_{prev}, years, and material type are from plant specific calculations.
- U_{en} = EAF Usage factor = $(U)(F_{en})$
- F_{en} = environmental fatigue correction factor – used to account for the Rx water environment.
- Bounding F_{en} is designated $F_{en80scr}$
- U_{prev}=previously calculated usage
- U_{80} uses the applicable NUREG/CR-6909 rev. 1 fatigue curve (except as noted) with 80-year projected cycles, and accounts for EPU.
- U_{en80} is the same as U_{80} with F_{en} applied. Allowable usage for U_{en80} is 1.0.

Table 4.3.7-4: Unit 2, Sentinel Locations - Fatigue Usage Summary

Location	Material Type	U_{prev}	U_{80}	U_{en80}
Joint 017, MS line D	CS	0.2529	0.0011	0.011
Primary steam cond. drain point 176	CS	0.5001	0.1966	0.763
Primary steam cond. drain point 40	CS	0.4988	0.3607	0.832
CRD HSR nozzle-vessel intersection	LAS	0.49	0.2348	0.877
Joint 500, recirc suction nozzle to pump	SS	0.0485	0.0778	0.662
Bottom head at shroud support	LAS	0.133	0.0726	0.627
RWCU and reactor drain point 15	CS	0.0927	0.0251	0.239
Core DP nozzle, cut 1 outside	NBA	0.274	0.3968	0.667
Joint 918, RHR return	CS	0.0768	0.0582	0.532
Joint 612, RHR return	CS	0.0751	0.0565	0.516
Joint 602, RHR return	SS	0.0963	0.1078	0.917
FWN overlay, pipe weld 8 path 1	CS	0.5651	0.1615	0.881
FW piping HELB location, point 85	CS	0.099	0.0958	0.366

General notes:

- MS=main steam; RHR=residual heat removal; SLC=standby liquid control; NBA=nickel-based alloy. HSR=hydraulic system return; RWCU=reactor water cleanup; DP=differential pressure; FW=feedwater; HELB=high energy line break.
- U_{prev}, years, and material type are from plant specific calculations.
- U_{en} = EAF Usage factor = (U)(F_{en})
- F_{en} = environmental fatigue correction factor – used to account for the Rx water environment.
- Bounding F_{en} is designated $F_{en80scr}$
- U_{prev}=previously calculated usage
- U_{80} uses the applicable NUREG/CR-6909 rev. 1 fatigue curve (except as noted) with 80-year projected cycles, and accounts for EPU.
- U_{en80} is the same as U_{80} with F_{en} applied. Allowable usage for U_{en80} is 1.0.

4.3.8 High Energy Line Break Analyses Based on Cumulative Fatigue Usage

TLAA Description:

As stated in Table 4.1-2 of NUREG-2192, a HELB analysis is considered a potential TLAA for the SPEO. The initial HNP LRA discussed the licensing basis pipe break criteria, which postulated pipe breaks at locations where the calculated fatigue usage exceeds a specified value. The NRC considers pipe break postulations based on CUF to be a TLAA because the fatigue calculation is a TLAA. HNP subsequently revised its LRA discussion of pipe break criteria to classify pipe break postulations based on fatigue CUF as TLAAs. The licensing basis pipe break criteria required that breaks be postulated at piping locations where the calculated CUF exceeded 0.1.

TLAA Evaluation

A high energy line break is not required to be postulated at a given Class 1 piping location if the design CUF calculated in accordance with ASME Section III, for that location, is less than or equal to 0.1. Therefore, these evaluations excluded locations within each high-energy Class 1 piping system that have a CUF value of 0.1 or less. Per NUREG-1803, in response to Open Item 4.1.3-1, HNP identified three piping locations where the calculated CUF exceeded 0.1. These locations are the bounding locations that are monitored during the PEO and thus require evaluation through the SPEO. 80-year projected HELB fatigue usage was calculated for the following monitored ASME Class 1 piping locations:

- Unit 1 SBLC
- Unit 2 feedwater
- Unit 2 RWCU

FatiguePro 3 was used to determine the overall effect of the cumulative numbers of transient cycles that have occurred at a given time and determines the CUF values resulting from the combination of transient cycles that have occurred. Two of the three subject locations' 80-year projected usage were initially calculated as below the allowable limit, however, the Unit 2 feedwater location's projected 80-year fatigue usage was initially calculated as 0.1034, which exceeds the allowable for not requiring a postulated HELB. Using more accurate (and less conservative) projections, this location's 80-year projected usage was recalculated as below the allowable and a postulated HELB is not required. See Table 4.3.8-1.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The 80-year projected cycle and fatigue usage was calculated as below the allowable limit for the Unit 1 SBLC piping and the Unit 2 feedwater and RWCU piping. The HELB analyses will be managed by the Fatigue Monitoring AMP (B.2.2.2) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.3.8-1: Monitored HELB Locations

Location	Usage as of 12/2023	Projected Fatigue Usage 60-year	Projected Fatigue Usage 80-year
Unit 1 SLC	0.0577	0.0616	0.0682
Unit 2 feedwater	0.0757	0.0877	< 0.1000(1)
Unit 2 RWCU	0.0242	0.0281	0.0331

Notes:

(1) Recalculated using less conservative projection weighting factors.

4.3.9 Cycle-dependent Fracture Mechanics or Flaw Evaluations

TLAA Description:

During the HNP Unit 1 2020 refueling outage, an indication was detected in weld HC-1 at the RPV closure head dollar plate weld which exceeded the acceptance standards of ASME Boiler and Pressure Vessel Code Section XI IWB-3510. ASME Section XI allows for the acceptance of a flaw for continued service if it meets the requirements of ASME Section XI, IWB-3600, Analytical Evaluation of Flaws. GE Hitachi Nuclear Energy prepared a fracture mechanics evaluation of this indication to determine the acceptability of the dollar plate weld indication through the SPEO. The evaluation of the indication was determined to be a TLAA.

TLAA Evaluation

The fracture mechanics evaluation for the dollar plate weld indication was performed in accordance with ASME Section XI, IWB-3600 and involved the flaw evaluation procedure described in ASME Section XI, Appendix A, Analysis of Flaws. The transients listed in the original Combustion Engineering stress report were reviewed and the stresses were updated considering current operating conditions, including the power uprates. The fatigue crack growth through 80 years was determined to be within limits and meets the fracture mechanics requirements specified in ASME Section XI, IWB-3612, Acceptance Criteria Based on Applied Stress Intensity Factor. Based on this evaluation, indication #16 detected in the HNP Unit 1 RPV closure head dollar plate weld is acceptable per the flaw acceptance criteria of ASME Section XI.

TLAA Disposition 10 CFR 54.21(c)(1)(ii)

The 80-year design and predicted fatigue crack growth is calculated as acceptable through the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

TLAA Description

Thermal, radiation, and cyclical aging analyses of plant electrical and instrumentation components, developed to meet 10 CFR 50.49 requirements, have been identified as a 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 EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a DBA such as a LOCA, HELB, or 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 EQ AMP that involve time-limited assumptions defined by the current operating term of 60 years have been identified as TLAAs for SLR because the EQ aging evaluations meet the criteria as defined in 10 CFR 54.3. Aging evaluations that qualify components for shorter periods, and that therefore require refurbishment, replacement, or extension of their qualified lives, are not TLAAs.

TLAA Evaluation

The Environmental Qualification of Electric Equipment AMP (B.2.2.1) meets the requirements of 10 CFR 50.49 for the applicable 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 Environmental Qualification of Electric Equipment AMP, 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 life. HNP maintains a record of equipment qualification in an auditable form for the entire period during which each covered item installed in the nuclear power plant or is stored for future use. The HNP EQ documentation packages are considered TLAAs per 10 CFR 54.21(c)(1).

The Environmental Qualification of Electric Equipment AMP is an existing program implemented in accordance with the requirements of 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii). 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 Environmental Qualification of Electric Equipment AMP manages the effects of component thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49 (f) qualification methods. 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.

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 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 because the Environmental Qualification of Electric Equipment AMP 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 AMP (10 CFR 50.49) and determined that it is an acceptable AMP to address EQ 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

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing the conservatism incorporated in the prior evaluation or by including new aging data. Reanalysis of an aging evaluation to extend the qualification of a component is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of the Environmental Qualification of Electric Equipment AMP. While a component life limiting condition may be due to thermal, radiation, or cyclical aging, most 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). As previously noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods

The Environmental Qualification of Electric Equipment AMP (B.2.2.1) may use 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 (i.e., 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 chief method used for a reanalysis. Temperature data, associated margins, and uncertainties used in an equipment EQ evaluation may be based on anticipated plant design temperatures found to be conservative when compared to actual plant temperature data. When used, plant temperature data may be obtained from monitors used for TS compliance, other installed monitors, measurements made by plant operators during rounds, dedicated monitors for EQ equipment or combinations of the above. A representative number of temperature measurements are conservatively evaluated to establish the temperature used in an aging evaluation. Plant environmental data may be used in an aging evaluation in different ways, such as directly applying the plant environmental data in the evaluation or using it to demonstrate conservatism when using plant design values for an evaluation. Any changes to the material activation energy values as part of a reanalysis require justification on a plant-specific basis. OE can also provide an additional basis to justify changes in the qualification of the equipment.

Underlying Assumptions

EQ equipment aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. A reanalysis will demonstrate that plant modifications and events maintain adequate margin consistent with the original analysis in accordance with 10 CFR 50.59 for certain margins and accounting for the unquantified uncertainties established in the EQ aging evaluation of the equipment. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of an EQ qualified component, the affected 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 should be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful. A modification to qualified life either by reanalysis or ongoing qualification must demonstrate that adequate margin is maintained consistent with the original analysis including unquantified uncertainties established in the original EQ equipment aging valuation.

Ongoing Qualification

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. For EQ equipment with a qualified life less than the required design life of the plant, "ongoing qualification" is a method of long-term qualification involving additional testing. Ongoing qualification or retesting, as described in IEEE Standard 323-1974, Section 6.6, "Ongoing Qualification", paragraphs (1) and (2), is a viable option for

HNP and is performed in accordance with accepted EQ industry and regulatory standards.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The Environmental Qualification of Electrical Equipment AMP (B.2.2.1) provides reasonable assurance that the applicable aging effects will be managed such that safety-related electrical equipment in harsh environments will continue to perform their intended functions consistent with the CLB throughout the SPEO. This is accomplished through effective monitoring techniques, acceptance criteria, corrective actions, and administrative controls associated with the AMP. Therefore, the Environmental Qualification of Electric Equipment AMP (B.2.2.1) is an acceptable AMP for SLR under **10 CFR 54.21(c)(1)(iii)**.

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS

The HNP Unit 1 and Unit 2 containments do not have pre-stressed tendons. As such, concrete containment tendon prestress is not a TLAA.

4.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE ANALYSES

The HNP Unit 1 primary containment was designed to the Class B requirements of the ASME Code, Section III, 1968 Edition with addenda through Summer 1968. The HNP Unit 2 primary containment was designed to the Class MC requirements of the ASME Code, Section III, 1971 Edition with addenda through Summer of 1971.

80-year fatigue projections have been performed for all monitored locations. Screening was performed based on bounding fatigue usage values from available fatigue analyses, which were scaled for 80 years, and EPU as applicable to determine whether additional locations should be monitored. The existing fatigue analyses of suppression chamber locations was revised to incorporate 80-year transient cycle projections. For any location with a resulting fatigue usage greater than 1.0, a detailed fatigue analysis was performed using existing fatigue tables and 80-year cycle projections.

The following Unit 1 torus locations were analyzed:

- Vent header/vent pipe intersection
- Vessel: ring girder / or saddle/shell intersection
- Torus penetration X-207

The following Unit 2 torus locations were analyzed:

- Vent system: downcomer penetration
- Vessel: ring girder / or saddle/shell intersection
- Torus penetration X-205
- Torus penetrations X-204A-D and X-208A and B

4.6.1 Fatigue Analysis of the Vessel Shell to Ring Girder

TLAA Description

Each unit's torus vessel shell at the ring girder or saddle/shell intersection is the bounding fatigue location for each unit (both the Unit 1 and Unit 2 suppression chamber locations). This is the currently monitored location and is bounding for each of the units.

TLAA Evaluation

Table 4.6-1 summarizes the results of the fatigue screening for the analyzed torus locations. The screening is performed using validated FatiguePro 3 software and is based on previous fatigue updates and plant data and events for the current period. The results confirm that the torus vessel at the ring girder or saddle/shell intersection remains the bounding location for fatigue. The 80-year projected fatigue screening values (U_{80}) for the torus vessel at the ring girder or saddle/shell intersection are 0.714 for Unit 1 and 0.622 for Unit 2. Because the projected fatigue usage for 80 years is less than 1.0 for all monitored locations, no additional locations screen in. Note that the 80-year projected fatigue values are lower than the corresponding 60-year fatigue screening values (U_{60})

values because no OBE or DBA events have occurred as of 12/31/2022, and therefore the 80-year projected values do not account for these events.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The fatigue analyses and corresponding CUF for HNP Unit 1 and Unit 2's suppression chamber locations will remain less than 1.0 and thus are acceptable through the SPEO.

The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (B.2.2.2) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

4.6.2 Fatigue Exemption (Waivers) for Main Steam Penetration Backing Ring and Containment Penetrations

TLAA Description

The updated fatigue exemption (waiver) of the backing ring for the HNP Unit 1 main steam containment penetrations are documented. The effects of 80-year projected cycles are included. Because HNP Unit 1's containment was designed to the Class B requirements of the 1968 Edition of the ASME Code, Section III, with Addenda through Summer 1968, and the HNP 2 containment was designed to the Class MC requirements of the 1971 Edition of the ASME Code, Section III, with Addenda through Summer 1971, either a fatigue analysis or a fatigue exemption analysis is required.

Fatigue exemptions (waivers) of the HNP Unit 1 and Unit 2 containment and containment penetrations for which there are no existing calculations are documented. The effects of 80-year projected cycles are included. This exemption analysis includes the primary containment (drywell), secondary containment (torus or suppression chamber), and containment penetrations.

TLAA Evaluation

The fatigue exemption evaluation shows that all general and N-415-1 criteria are met. In accordance with the rules of N-415.1 of Section III of the ASME Code, the backing ring for the Unit 1 main steam containment penetrations is exempt from fatigue analysis for an 80-year life.

In accordance with the rules of NB-3222.4(d) of the ASME Code, the containment and containment penetrations for HNP Units 1 and 2 are exempt from fatigue analysis for an 80-year life.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The fatigue analyses of the backing ring for Unit 1 main steam containment penetrations and for the containment and containment penetrations fatigue waivers will be managed by the Fatigue Monitoring AMP through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**. The Fatigue Monitoring AMP (B.2.2.2) 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 4.6-1: 80-Year Fatigue Screening Suppression Chamber Locations

Unit	Location	U_{60}, Previous	Fatigue Usage (U_{80})
1	Vent header/vent pipe intersection	0.784	0.652
1	Vessel: ring girder / or saddle/shell intersection	0.955	0.714
1	Torus penetration X-207	0.626	0.457
2	Vent system: downcomer penetration	0.445	0.256
2	Vessel: ring girder / or saddle/shell intersection	0.799	0.622
2	Torus penetration X-205	0.366	0.313
2	Torus penetrations X-204A-D and X-208A/B	0.534	0.355

4.7 OTHER PLANT-SPECIFIC TLAAs

4.7.1 Fatigue of Cranes (Crane Cycle Limits)

TLAA Description

Cranes within the scope of SLR 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 scope of this calculation includes the Unit 1 reactor building overhead crane, the Unit 1 turbine building crane, and the Unit 2 turbine building crane.

These three cranes comply with the intent of CMAA-70, "Specifications for Electric Overhead Traveling Cranes," (Reference 4.8.31), meet the intent of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," Guideline 7 (Reference 4.8.32), and are therefore within the scope of SLR. Because CMAA-70 specifies a design load cycle limit which provides a basis for acceptability of fatigue over the life of these cranes, these analyses are considered TLAAs that must be evaluated for the SPEO.

TLAA Evaluation

This TLAA only considers loads greater than 50 percent of the three subject cranes' capacity and that any load below 50 percent of their rated capacity has no effect on the life expectancy of the crane. This is based upon the HNP-1 FSAR, Section 10.20.5, and is judged applicable to the three subject cranes. The total projected load cycles for the Unit 1 reactor building crane through the 80-year SPEO are estimated to be 4840 lifts. The total projected load cycles for the Unit 1 and Unit 2 turbine building cranes through the 80-year SPEO are 492 and 490 lifts, respectively. The projected number of load cycles for the three subject cranes is significantly less than the CMAA-70 limiting value of 20,000 cycles.

The defined service life as measured in load cycles for the three subject cranes is well within the maximum number of load cycles specified in CMAA Specification 70.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The Unit 1 reactor building overhead crane, the Unit 1 turbine building crane, and the Unit 2 turbine building crane load cycle evaluations will remain valid through the SPEO in accordance with **10 CFR 54.21(c)(1)(i)**.

4.7.2 Corrosion Allowance Calculations

TLAA Description

As documented in LRA Section 4.3, an allowance for corrosion was made in determining the appropriate thickness for pressure retaining components in the design of HNP. Only those analyses containing an assumption of a corrosion allowance that also tied the allowance to a 40-year or 60-year operating life meet 10 CFR 54.3 Criterion 3. The equipment designed and supplied by both Bechtel and GE is included in the SLRA review.

TLAA Evaluation

Per the LRA, Bechtel evaluated the RHR service water (RHRSW) system piping and the plant service water (PSW) system piping in accordance with NRC GLs 89-13 (Reference 4.8.33) and 90-05 (Reference 4.8.34). Much of this piping is in-scope for SLR.

Bechtel used the corrosion allowance from the pipe specification in calculations to develop piping measurement evaluation levels based in part upon the expected pipe thickness and its predicted wear for the remaining service life. The corrosion allowance was assumed to be the maximum allowed for the 40-year service life of the piping. The corrosion rate is used to predict the expected pipe thickness and to develop the minimum acceptable as-found thickness of the pipe, and thus is considered a TLAA.

Per the HNP LRA, a time-dependent corrosion rate was used by GE to calculate the HNP Units 1 and 2 corrosion allowance for the reactor vessels based upon a 40-year assumed vessel service life. Since this corrosion allowance was determined to meet all six criteria, the corrosion allowance is a TLAA. A corrosion allowance for the HNP reactor system's austenitic stainless steel components and general piping was not explicitly calculated. The corrosion rate for stainless steel under BWR conditions is very low.

The Open-Cycle Cooling Water System AMP (B.2.3.11) uses inspection and test results to determine corrosion rates and any required corrective actions. This AMP manages the aging of the internal surfaces of piping, piping components, and heat exchanger and chiller components exposed to a raw water environment (i.e., PSW) and RHRSW that remove heat from SR SSCs during the SPEO. The AMP's routine inspection and maintenance will provide reasonable assurance that loss of material, corrosion, erosion, cracking, fouling, and biofouling will not degrade the performance of safety-related systems serviced by the PSW and RHRSW systems.

The Water Chemistry AMP's (B.2.3.2) objectives include mitigation of loss of material due to corrosion and mitigation of cracking due to SCC and related mechanisms. It relies on monitoring and control of reactor water chemistry based on industry guidelines. The RPV, RVI, and the RHR system are some of the LR systems that credit the Water Chemistry AMP. The AMP provides reasonable assurance that loss of material due to corrosion will be managed such that the HNP reactor system's components and general piping will continue to perform their intended functions consistent with the CLB throughout the SPEO.

The One-Time Inspection AMP (B.2.3.20) verifies the effectiveness of the Water Chemistry AMP (B.2.3.2).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii).

For the HNP pressure retaining components, the Open-Cycle Cooling Water System AMP (B.2.3.11), the Water Chemistry AMP (B.2.3.2), and the One-Time Inspection AMP (B.2.3.20) will continue to manage the effects of aging (corrosion) through the SPEO in accordance with existing maintenance and surveillance procedures in accordance with **10 CFR 54.21(c)(1)(iii)**.

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APPENDIX A

FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

HATCH NUCLEAR 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 HNP Units 1 and 2 is required by 10 CFR 54.21(d) to include a FSAR supplement. This chapter comprises the FSAR supplement of the HNP Subsequent License Renewal Application (SLRA) and includes the following sections:

Section A.1.1 contains a listing of the 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 Southern Nuclear Company (SNC) Quality Assurance (QA) Program and the AMPs' corrective actions, confirmation process, and administrative controls elements.

Section A.1.4 contains a summary of the Operating Experience (OE) Program.

Section A.2 contains a summary of the 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 SLR Implementation Action 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 HNP SLR are listed in Table A-1 and described in Section A.2. The AMPs are listed in the order that they appear in NUREG-2191, with the Chapter X AMPs first, followed by the Chapter XI AMPs. The AMPs are categorized as either existing AMPs or new AMPs for SLR. The existing 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 AMPs at the time of the SLRA submittal. Implementation actions, which include AMP enhancements and implementation schedules for AMPs are identified in the SLR Implementation Action List within Section A.4.

Table A-1
List of HNP Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
X.E1	Environmental Qualification of Electric Equipment (Section A.2.1.1)	Existing
X.M1	Fatigue Monitoring (Section A.2.1.2)	Existing
X.M2	Neutron Fluence Monitoring (Section A.2.1.3)	New
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
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.E5	Fuse Holders (Section A.2.2.41)	New
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.2.42)	New
XI.E7	High-Voltage Insulators (Section A.2.2.43)	New
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)	New
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

Table A-1
List of HNP Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
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 (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)	New
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)	Existing
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)	New
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)	New
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

Table A-1
List of HNP Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
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
N/A (Plant-specific)	RHR Heat Exchanger Augmented Inspection (Section A.2.3.1)	Existing
N/A (Plant-specific)	Torus Submerged Components Inspection (Section A.2.3.2)	Existing

A.1.2. Time-Limited Aging Analyses

The TLAAs applicable to HNP 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 (USE) Reduction Due to Neutron Embrittlement	A.3.2.2
	Adjusted Reference Temperature (ART) 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
	Susceptibility to IASCC	A.3.2.8
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 Fatigue Analysis	A.3.3.5
	ASME Section III, Class 2 and 3 and ANSI B31.1 and Associated HELB Analyses	A.3.3.6
	Environmentally-Assisted Fatigue	A.3.3.7
	High Energy Line Break Analyses	A.3.3.8

Table A-2
List of Time-Limited Aging Analyses

Category (Section)	Time-Limited Aging Analyses Name	Section
	Based on Cumulative Fatigue Usage	
	Cycle-dependent Fracture Mechanics or Flaw Evaluations	A.3.3.9
Environmental Qualification (EQ) of Electric Equipment (A.3.4)	Environmental Qualification (EQ) of Electric Equipment	A.3.4
Concrete Containment Tendon Prestress (A.3.5)	Concrete Containment Tendon Prestress	A.3.5
Containment Liner Plate, Metal Containments and Penetrations Fatigue Analyses (A.3.6)	Fatigue Analysis of the Vessel Shell to Ring Girder	A.3.6.1
	Fatigue Exemption (Waivers) for Main Steam Penetration Backing Ring and Containment Penetrations	A.3.6.2
Other Plant-Specific TLAA (A.3.7)	Fatigue of Cranes (Crane Cycle Limits)	A.3.7.1
	Corrosion Allowance Calculations	A.3.7.2

A.1.3. Quality Assurance Program and Administrative Controls

The QA Program 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 SNC 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 SNC QA Program are applicable to all AMPs and activities during the SPEO. The SNC QA Program procedures, review and approval processes, and administrative controls are implemented, as described in the SNC QA Topical Report, in accordance with the requirements of 10 CFR Part 50, Appendix B. The SNC QA Program applies to all SCs that have aging effects managed by an AMP. Corrective actions and administrative (document) control for both SR and NSR SCs are accomplished in accordance with the established 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 OE Program captures the OE from plant-specific and industry sources and is systematically reviewed on an ongoing basis in accordance with the SNC 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 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 OE Program.

A.2 Aging Management Programs

A.2.1 NUREG-2191 Chapter X Aging Management Programs

This section provides FSAR summaries of the NUREG-2191 Chapter X AMPs associated with TLAAs.

A.2.1.1 Environmental Qualification of Electric Equipment

The Environmental Qualification of Electrical Components AMP is an existing AMP that 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 EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform their safety function in those harsh environments after the effects of in-service aging. 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. The Environmental Qualification of Electrical Equipment AMP is implemented in accordance with 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii).

A.2.1.2 Fatigue Monitoring

The Fatigue Monitoring AMP is an existing monitoring program that manages fatigue damage of the reactor pressure vessel (RPV) components, the torus, and reactor coolant pressure boundary Class 1 piping components and high energy line break (HELB) components. This AMP is used to manage fatigue or other types of cyclical loading TLAAs in accordance with the acceptance criterion in 10 CFR 54.21(c)(1)(iii). The AMP monitors and tracks the number of occurrences and severity of design basis transients assessed in the applicable fatigue or cyclical loading analyses, including those in applicable cumulative usage factor (CUF) analyses, environmentally assisted fatigue (CUF_{en}) analyses, maximum allowable stress range reduction/expansion stress analyses for American National Standards Institute (ANSI) B31.1 and ASME Code Class 2 and 3 components, ASME III fatigue waiver analyses, cycle-based flaw growth analyses, and flaw tolerance analyses.

The 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, design transient cycle limit values, and predicted flaw size values. The AMP also sets applicable acceptance criteria (limits) on these parameters. Therefore, the program has two aspects, one to verify the continued acceptability of existing analyses through cycle counting or parameter monitoring and the other to provide periodically updated evaluations of the analyses to demonstrate that they continue to meet the appropriate limits.

When a program acceptance criterion is exceeded or the severity of an actual transient exceeds the design transient definition, the condition is entered into the 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. This AMP is required by plant technical specification 5.5.5, Component Cyclic or Transient Limit.

A.2.1.3 Neutron Fluence Monitoring

The Neutron Fluence Monitoring AMP is a new condition monitoring program that will monitor and track accumulated neutron fluence (integrated, time-dependent neutron flux exposures) to the RPV and reactor vessel internal (RVI) components to ensure that applicable RPV neutron embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessments for reactor internal components will remain within their applicable limits.

The Neutron Fluence Monitoring AMP will verify the continued acceptability of existing analyses through neutron fluence monitoring, assess susceptibility of RVI components to neutron irradiation-related damage, and will determine and monitor the extent of the RPV beltline region. Thus, the AMP will ensure the analyses involving neutron fluence inputs continue to meet the appropriate limits defined in the CLB.

Monitoring will be performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in reports approved by the NRC. For fluence monitoring activities that apply to the beltline region of the RPV, the calculational methods are generally performed in a manner that is consistent with the Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." Additional justification will be used as necessary for neutron fluence monitoring, regarding methods that are applied to RPV locations outside of the beltline region of the vessels or to reactor internal components.

The Neutron Fluence Monitoring AMP results will be compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for RPV components. This includes, but is not limited to, the neutron fluence inputs for the RPV USE analyses and pressure temperature limits analyses that are required to be performed in accordance with 10 CFR Part 50, Appendix G. Comparisons to the neutron fluence inputs for other analyses include those for mean reference nil-ductility temperature (RT_{NDT}), and probability of failure analyses for RPV circumferential and axial shell welds, core reflood design analyses, and aging effect assessments for 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 AMP, provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in technical specifications or in specific regulations of 10 CFR Part 50 apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

A.2.2 NUREG-2191 Chapter XI Aging Management Programs

This section provides FSAR 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 ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD (ISI) aging management program (AMP) is an existing AMP that is part of the SNC Inservice Inspection Program and supplemented by implementing the guidelines of the boiling water reactor vessel internals project (BWRVIP) program documents. The ISI AMP provides for the condition monitoring of ASME Code Class 1, 2, and 3 pressure-retaining components and their integral attachments.

The ISI AMP manages the aging effects of loss of material and cracking. The aging effects of loss of preload for pressure-retaining bolting is managed by the Bolting Integrity AMP and aging effects of the loss of fracture toughness is covered by the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP. The ISI AMP consists of periodic volumetric, surface, and/or visual examination ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casing, valve and bodies, integral attachments, and pressure-retaining bolting for assessment, signs of degradation, and corrective actions. The ISI 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 during the SLRA review.

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.

A.2.2.2 Water Chemistry

The Water Chemistry AMP, previously known as the Reactor Water Chemistry Control, Fuel Pool Chemistry Control, Suppression Pool Chemistry Control, and Demineralized Water and Condensate Storage Tank Chemistry Control AMPs, 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 Water Chemistry AMP controls treated water for impurities (e.g., chloride and sulfate) that accelerate corrosion. The 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 BWRVIP-190 Revision 2.

A.2.2.3 Reactor Head Closure Stud Bolting

The Reactor Head Closure Stud Bolting AMP is a new preventive and condition monitoring AMP that manages reactor head closure studs and associated RPV head flange threads, nuts, washers, and bushings, for cracking and loss of material. The AMP will be implemented through station procedures based on the examination requirements specified in ASME Code, Section XI, Subsection IWB, Table IWB-2500-1 and preventive measures to mitigate cracking as delineated in NRC RG 1.65 Revision 1. These preventive measures include not using metal-plated stud bolting, using manganese phosphate or other acceptable surface treatments, and using stable lubricants.

The Reactor Head Closure Stud Bolting AMP will manage 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 will be accomplished through effective volumetric testing, visual and surface monitoring techniques, acceptance criteria, corrective actions, and administrative controls.

This Reactor Head Closure Stud Bolting AMP will also include procurement requirements for reactor head closure stud material to assure that the maximum yield strength of newly purchased stud material is limited to a measured yield strength less than 150 ksi or an ultimate tensile strength not exceeding 170 ksi.

A.2.2.4 BWR Vessel ID Attachment Welds

The BWR Vessel ID Attachment Welds aging management program is an existing condition monitoring program that manages cracking of the reactor vessel interior attachment welds. This program relies on visual examinations to detect cracking. The examination scope, frequencies, and methods are in accordance with ASME Code, Section XI, Table IWB-2500-1, Examination Category B-N-2, applicable NRC approved ASME Code alternatives, and BWRVIP-48 Revision 2. The scope of the examinations is expanded when flaws are detected.

Any indications are evaluated in accordance with ASME Code, Section XI, or the guidance in BWRVIP-48 Revision 2. Crack growth evaluations follow the guidance in BWRVIP-14-A, BWRVIP-59-A, or BWRVIP-60-A, as appropriate. The acceptance criteria are in BWRVIP-48 Revision 2 and ASME Code, Section XI, Subarticle IWB-3520. Repair and replacement activities are conducted in accordance with BWRVIP-52-A. Additional inspections and evaluation of the core spray piping brackets are performed in accordance with BWRVIP-18 Revision 2-A. Additional inspections and evaluation of the jet pump riser brace are performed in accordance with BWRVIP-41 Revision 4-A.

A.2.2.5 BWR Stress Corrosion Cracking

The BWR Stress Corrosion Cracking AMP is an existing AMP that manages IGSCC in BWR coolant pressure boundary piping made of stainless steel, stainless steel clad low alloy steel and nickel alloy components as delineated in NUREG–0313, Revision 2, and NRC Generic Letter (GL) 88-01 and its Supplement 1. The AMP is applicable to all piping, piping components and piping welds made of austenitic stainless steel, stainless steel clad low alloy 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 Stress Corrosion Cracking AMP is part of the NRC reviewed ISI Program and provides for condition monitoring of the material susceptible to BWR SCC in accordance with the applicable requirements of ASME Section XI, NUREG-0313, and NRC GL-88-01 guidance. This program is a condition monitoring program which also relies on countermeasures. The BWR Stress Corrosion Cracking AMP focuses on (1) managing and implementing countermeasures to mitigate IGSCC by maintaining high purity water which reduces susceptibility to SCC or IGSCC in accordance with the Water Chemistry AMP and (2) performing ISI to monitor IGSCC and its effects on the intended function of BWR piping components within the scope of this program.

The program detects and sizes cracks and detects leakage by using the examination and inspection guidelines delineated in ASME Section XI, NUREG-0313, Revision 2, and NRC GL 88-01 as applicable. This program relies on the staff-approved positions that are described in NUREG–0313, Revision 2, and GL 88-01.

Modifications to the extent and schedule of inspection in NRC GL 88-01 are implemented in accordance with the inspection guidance in staff-approved BWRVIP-75-A . This AMP utilizes BWRVIP-75-A for implementation of an augmented program that provides examination for detection of IGSCC per the ISI Plan.

This program applies to the following systems:

- RPV
- Nuclear boiler
- Reactor recirculation

A.2.2.6 BWR Penetrations

The BWR Penetrations AMP is an existing AMP that is part of the ISI Program that manages cracking due to cyclic loading, SCC and IGSCC for BWR vessel penetrations and nozzles. The in-scope components for this AMP includes vessel instrumentation penetrations, control rod drive (CRD) housing stub tube and incore-monitoring housing (ICMH) penetrations, and standby liquid control (SBLC) nozzles/Core ΔP nozzles.

The AMP includes inspection and flaw evaluation in conformance with the guidelines of NRC-approved BWRVIP Topical Reports BWRVIP-49-A , BWRVIP-47-A, and BWRVIP-27-A. The AMP uses non-destructive testing, inspections, water chemistry control, and repairs when required. This AMP monitors the effects of SCC, IGSCC, and cyclic loading on the intended function of the component by detection and sizing of cracks by ISI in accordance with the guidelines of approved BWRVIP-49-A, BWRVIP-47-A or BWRVIP-27-A , as well as the requirements of ASME Code, Section XI, Table IWB-2500-1. Inspections are scheduled and performed in accordance with the approved ASME Section XI Edition / Addenda as outlined in the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD AMP. BWR water chemistry is controlled per the Water Chemistry AMP and BWRVIP Mitigation Program.

Volumetric, surface and visual examinations and leakage test provide adequate assurance that any flaw(s) that might have propagated through the subject welds are identified and repaired prior to returning the plant to power operation. Identified flaws are repaired or replaced in accordance with Hatch Vessel and Internals Program – Reactor Vessel Internals Bases Document including guidelines provided in BWRVIP-58-A, BWRVIP-57-A, BWRVIP-55-A and BWRVIP-53-A.

A.2.2.7 BWR Vessel Internals

The BWR Vessel Internals program is an existing program that includes inspections and flaw evaluations in conformance with the guidelines of applicable 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 program manages the effects of cracking due to SCC, IGSCC, or irradiation assisted stress corrosion cracking (IASCC), cracking due to cyclic loading (including flow-induced vibration), loss of material due to wear, loss of fracture toughness due to neutron or thermal embrittlement, and loss of preload due to thermal or irradiation-enhanced stress relaxation.

The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB 2500-1. However, HNP utilizes an NRC Approved Request for Alternative Implementation of the BWRVIP Program for Vessel Internals in lieu of the requirements of ASME Code, Section XI. The NRC found that the proposed alternative provided an acceptable level of quality and safety for the vessel internals components because the proposed alternate provides for equivalent or superior flaw detection and characterization with an examination frequency that is equivalent or more frequent than the ASME Code requirements. 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.

The program is updated periodically as required by 10 CFR 50.55a and the BWRVIP.

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.

A.2.2.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is a new AMP that will determine the potential significance of thermal aging embrittlement of cast austenitic stainless steel (CASS) components and detect the effects of loss of fracture toughness due to thermal embrittlement of CASS pump casings. The scope of the program includes ASME Code Class 1 piping components constructed from CASS with service conditions above 250°C (482°F).

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP will include a screening methodology to determine component susceptibility to thermal embrittlement based on casting method, molybdenum content, and percent ferrite. The criteria is set forth in NUREG/CR–4513, Revision 2 with errata (March 2021), the potential significance of thermal aging embrittlement of CASS materials is determined in terms of casting method, molybdenum content, nickel content, and ferrite content. Based on the results of this screen, if any components are determined to be potentially susceptible to thermal embrittlement of CASS, aging management will be accomplished through either (1) qualified visual inspections, such as EVT-1 enhanced visual examination; (2) a qualified ultrasonic testing (UT) methodology; or (3) a component specific flaw tolerance evaluation in accordance with the ASME Code, Section XI.

Examination methods that meet the criteria of the ASME Code, Section XI, Appendix VIII are acceptable. Inspection schedules will be in accordance with ASME Code, Section XI, IWB-2400 or IWC-2400 per the ISI program, as well as, reliable examination methods, and qualified inspection personnel will be identified to provide timely and reliable detection of cracks. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components for which thermal aging embrittlement is not significant. Flaws detected in CASS components will be evaluated in accordance with the applicable procedures of ASME Code, Section XI. This AMP 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. NUREG/CR–4513, Revision 2 with errata provides methods for predicting the fracture toughness of thermally aged CASS materials with delta ferrite content up to 40 percent.

For valve bodies, screening for significance of thermal aging embrittlement is not needed (and thus there are no aging management review items). For valve bodies greater than or equal to 4 inches nominal pipe size (NPS), the existing ASME Code, Section XI inspection requirements are adequate. ASME Code, Section XI, Subsection IWB requires only surface examination of valve bodies less than 4 inches NPS. For valve bodies less than 4 inches NPS, the adequacy of ISI according to ASME Code, Section XI has been demonstrated by an NRC-performed bounding integrity analysis (May 19, 2000 Grime's letter, NRC000213, License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components").

A.2.2.9 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion AMP is an existing condition monitoring program which is designed to monitor pipe component wear in those systems that have been determined to be susceptible to flow-accelerated corrosion (FAC) related loss of material. This program may also be used to manage wall thinning due to erosion mechanisms that are not managed by other programs. The program is based on commitments made for an ongoing monitoring program in response to the NRC GL 89-08 and relies on implementation of the EPRI guidelines in Nuclear Safety Analysis Center NSAC-202L-R4, "Recommendations for an Effective Flow Accelerated Corrosion Program."

The objective of the program is to ensure that the damage caused by FAC will not cause component failure resulting in an unplanned outage. This objective is accomplished by predicting the rate of degradation of components by use of predictive analytical software and taking corrective actions once the degradation is detected. The predictive analytical software uses the implementation guidance of NSAC-202L-R4.

This program includes: (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analyses of FAC models and, with consideration of 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 program includes the use of predictive analytical software that uses the implementation guidance of NSAC-202L-R4. The FAC AMP also manages wall thinning caused by erosion mechanisms such as cavitation, flashing, and liquid drop impingement. Susceptible components are also identified through OE and industry guidance.

A.2.2.10 Bolting Integrity

The Bolting Integrity AMP is an existing condition monitoring program which manages the aging effects associated with closure bolting for pressure-retaining components in the scope of license renewal (LR). 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 nuclear procedure 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 3002015824 and EPRI Report 3002008061.

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, microbiologically influenced 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 compressed air or gas for which leakage is difficult to detect.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP includes inspections of SR and NSR closure bolting and supplements this Bolting Integrity AMP.

Submerged bolting in the suppression pool is managed by the Torus Submerged Components Inspections AMP (A.2.3.2) and supplements the Bolting Integrity AMP.

The aging effects associated with the following types of bolting are not managed by the Bolting Integrity AMP:

- Closure bolting for HVAC systems is managed by the External Surfaces Monitoring of Mechanical Components AMP.
- Reactor head closure studs are managed by the Reactor Head Closure Stud Bolting AMP.
- Bolting internal to the reactor vessel is managed by BWR Vessel Internals AMP.
- Bolts associated with splices or electrical connections are managed by the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.
- Buried and underground piping valves, fasteners, and tanks (loss of material aging effect only, all other aging effects for these bolts are managed by the Bolting Integrity AMP) are managed by Buried and Underground Piping and Tanks AMP.

A.2.2.11 Open-Cycle Cooling Water System

The Open-Cycle Cooling water AMP, previously known as the Plant Service Water and RHR Service Water Inspection Program AMP, is an existing AMP that mitigates the aging effects of loss of material due to corrosion, erosion, cracking, and reduction of heat transfer due to fouling and biofouling in components exposed to raw water. This program relies, in part, on implementing the response to NRC GL 89-13, Service Water System Problems Affecting Safety-Related Equipment.

The Open-Cycle Cooling Water System AMP manages the aging effects of components in raw water systems by using a combination of preventive, condition monitoring, and performance monitoring activities. These activities include; (1) surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, and fouling; (2) inspection of components for signs of loss of material, corrosion, erosion, cracking, fouling, and biofouling; and (3) testing of the heat transfer capability of heat exchangers that remove heat from components important to safety.

A.2.2.12 Closed Treated Water Systems

The Closed Treated Water Systems AMP, formerly known as the Closed Cooling Water Chemistry Control AMP, is an existing AMP that is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. This AMP consists of (1) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion are minimized; (2) chemical testing of the water so that the water treatment program maintains the water chemistry within acceptable guidelines; and (3) inspections to determine the presence or extent of degradation. The Closed Treated Water Systems AMP uses as applicable, EPRI 3002000590, "Closed Cooling Water Chemistry Guideline," and may also include microbiological testing.

A.2.2.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The Inspection of Overhead Heavy Load & Light Load (Related to Refueling) Handling Systems AMP, previously known as the Overhead Crane and Refueling Platform Inspection AMP, is an existing AMP that evaluates the effectiveness of maintenance monitoring activities for cranes and hoists. The program includes periodic visual inspections 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. This program relies on the guidance in NUREG-0612, ASME B30.2, and other appropriate standards in the ASME B30 series. These cranes must also comply with the maintenance rule requirements provided in 10 CFR 50.65.

A.2.2.14 Compressed Air Monitoring

The Compressed Air Monitoring AMP is a new program which will inspect, monitor, and test the instrument and service air systems to provide reasonable assurance that the systems will perform their intended function. The Compressed Air Monitoring AMP will manage 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 Compressed Air Monitoring AMP will include monitoring of moisture and other contaminants as a preventive measure to keep compressed air quality within specified limits. The AMP will incorporate the guidance from the most current ANSI/ISA standards, and the guidance from ASME OM 2012, Division 2, Part 28, and EPRI technical report TR-108147 for testing and monitoring of air quality and moisture.

Opportunistic visual inspections of compressed air system components located downstream of the compressed air system air dryers, or for components exposed to an internal gas environment, will be performed in accordance with ASME OM-2012, Division 2, Part 28 to detect signs of corrosion and abnormal corrosion products that might indicate loss of material within the system. Additionally, inspection and test results will be trended to provide for the timely detection of aging effects prior to loss of intended function.

A.2.2.15 Fire Protection

The Fire Protection AMP is an existing condition monitoring and performance monitoring program that includes a fire barrier visual inspection program, and a CO_2 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), electrical raceway fire barrier system (ERFBS), fireproofing, fire damper housing and ductwork, and periodic visual inspection and functional tests of associated fire doors to ensure that their functionality is maintained. The fire protection (FP) program and procedures include periodic visual inspection and testing of the CO_2 suppression system utilizing National Fire Protection Association (NFPA) as guidance.

A.2.2.16 Fire Water System

The Fire Water System AMP is an existing AMP. This AMP manages aging effects associated with loss of material, wall thinning, hardening or loss of strength, and flow blockage due to fouling by performing periodic visual and volumetric inspections, tests, and flushes per the HNP procedures.

Portions of the water-based FP 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 National Fire Protection Association Code (NFPA) 25 are managed by performing (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 FP systems are implemented to provide reasonable assurance that the fire water systems can perform their intended functions. Inspections and testing are performed in accordance with the nuclear insurance carrier's FP system testing requirements and the guidance of applicable NFPA Codes and Standards.

The wet pipe sprinkler systems are not exposed to any harsh or corrosive environments as defined in NFPA 25 Section 5.3.1.1.2 and Section A.5.3.1.1.2 of Annex A of NFPA 25. The wet pipe sprinklers are exposed only to an external environment of plant indoor air and internal environments of raw water.

The water-based FP 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 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.

Inspection and test frequencies are governed by the NRC approved FP program as stated in the NFPA 805 Safety Evaluation Report (SER) (ML20066F592). Potential future changes to the frequencies of inspections and testing would be done in accordance with the approved NFPA 805 program and site procedures.

A.2.2.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The Outdoor and Large Atmospheric Metallic Storage Tanks AMP, previously known as the Condensate Storage Tank Inspection AMP, is an existing AMP that mitigates the aging effects of loss of material and cracking due to corrosion. The scope of this program includes the Unit 1 and Unit 2 condensate storage tanks (CSTs). The Unit 1 CST is fabricated from aluminum and the Unit 2 CST is fabricated from stainless steel. The CSTs contain treated water, are not insulated, and sit on concrete. As such, the bottoms of the tanks are inaccessible for direct visual inspection.

The internal and external areas of the CSTs are exposed to air/condensation, concrete, and treated water environments. The Outdoor and Large Atmospheric Metallic Storage Tanks AMP manages the aging effects of the condensate storage tanks by using both one-time and periodic inspection activities. The activities consist of visual inspections, surface examinations, and UT for interior and exterior surfaces for signs of loss of material, corrosion, and cracking. Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specific tasks. 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. The inspections also include physical manipulation of caulking and sealants. The inspection results are compared to acceptance criteria and include trending to allow corrective actions to be taken prior to loss of intended function.

A.2.2.18 Fuel Oil Chemistry

The 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 visual inspection of the fuel oil storage tanks (FOSTs) and diesel generator day tanks internal surfaces. The fire pump diesel storage tanks are periodically drained and cleaned. Volumetric examinations are performed on the fire pump diesel storage tanks to verify wall thickness periodically in lieu of visual inspections. Volumetric examinations are performed on all tanks to assess identified degradation and to monitor for wall loss of the fuel oil tanks. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the HNP Technical Specifications. Guidelines of American Society for Testing and Materials (ASTM) Standards, including ASTM D975 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, microbiocide additives, 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 One-Time Inspection AMP (Section A.2.2.20).

A.2.2.19 Reactor Vessel Material Surveillance

The Reactor Vessel Material Surveillance AMP is an existing AMP that monitors the changes in the fracture toughness of the ferritic reactor vessel beltline materials due to neutron irradiation embrittlement through the periodic testing of material specimens at different intervals, monitors irradiation embrittlement to a neutron fluence level that is greater than the projected peak neutron fluence of interest projected to the end of the SPEO and provides adequate dosimetry monitoring during the SPEO. 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. The AMP uses neutron dosimeters to monitor the neutron fluence of the surveillance capsules and to provide information to benchmark neutron fluence calculations. The use of dosimetry to monitor neutron fluence is in accordance with BWRVIP-321, Revision 1-A. The fluence projection will continue to be based on the capsule dosimetry unless a major change to the core design or management is undertaken in the future. HNP will continue to determine vessel fluences as needed, in accordance with RG 1.190. The AMP provides for testing and evaluation of in-core surveillance capsule tensile and Charpy specimens and evaluation of capsule neutron exposure for the purpose of evaluating the results of operation on RPV beltline material USE and nil-ductility transition temperature (NDTT).

The Reactor Vessel Material Surveillance Program is part of the BWRVIP Integrated Surveillance Program (ISP). HNP is committed to use the ISP as indicated in the amendment issued by the NRC regarding the implementation of the BWRVIP ISP. The ISP meets the requirements for an integrated surveillance program in 10 CFR 50, Appendix H. Thus, the Reactor Vessel Material Surveillance program meets the requirements of 10 CFR 50, Appendix H.

For the SPEO, the Reactor Vessel Material Surveillance AMP is as described by BWRVIP-321 Revision 1-A which 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 as concluded by the NRC. The ISP capsule insertion, withdrawal, testing schedule is as described in section 8 of BWRVIP-321 Revision 1-A. Because the selection of materials to be reconstituted and tested will depend on which BWRs pursue SLR and need additional surveillance data, the BWRVIP will notify the NRC of test plans and the timeline for reporting test results as described in section 10.3.2 of BWRVIP-321 Revision 1-A. There are no specific acceptance criteria that apply to the surveillance data themselves.

The implementation of the ISP is consistent with the latest version of the ISP plan that has received approval by the NRC for the SPEO.

A.2.2.20 One-Time Inspection

The One-Time Inspection AMP is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (1) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO; (2) the insignificance of an aging effect; and (3) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the One-Time Inspection AMP include: (1) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and OE, (2) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) 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 One-Time Inspection AMP is used to verify the effectiveness of the Water Chemistry (A.2.2.2), Fuel Oil Chemistry (A.2.2.18), and Lubricating Oil Analysis (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 Selective Leaching

The Selective Leaching AMP is a new condition monitoring program that includes inspections of components that may be susceptible to loss of material due to selective leaching. One-time inspections for components exposed to a closed-cycle cooling water (CCCW) or treated water environment will be conducted, based on HNP plant-specific OE which has not revealed selective leaching in these environments. Visual inspections coupled with mechanical examination techniques such as chipping or scraping are conducted. Opportunistic and periodic inspections are conducted for raw water and soil environments. 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 and soil environments. Inspections and tests are conducted to determine whether loss of material will affect the ability of the components to perform their intended function for the SPEO. Inspections are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the 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.

A.2.2.22 ASME Code Class 1 Small-Bore Piping

The ASME Code Class 1 Small-Bore Piping AMP is a new condition monitoring 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 provides one-time and periodic volumetric inspection of a sample of 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 there is no need to manage age-related degradation. The ASME Code Class 1 Small-Bore Piping AMP includes locations that 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.

Volumetric inspections of a sample of small-bore Class 1 piping are performed to verify that cracking is not occurring during the SPEO. Butt weld inspection will be a one-time inspection with a sample size of 3 percent per unit, up to a maximum of 10 welds per unit, because HNP has no history of age-related cracking in butt welded piping. Socket weld inspection will be periodic with a sample size of 10 percent per unit, up to a maximum of 25 welds per unit, because HNP has experienced age-related cracking in socket welded piping. For socket welds, the first examination will be completed within 6 years of the SPEO and subsequent examinations will be completed every 10 years thereafter. Selection of inspection location will employ a methodology to select the most susceptible and risk-significant welds. Destructive examination may be performed in lieu of volumetric examination. 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 corrective actions is then established.

A.2.2.23 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components AMP is a new condition monitoring program that will manage 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 External Surfaces Monitoring of Mechanical Components AMP will also inspect the integrity of coated surfaces as an effective method for managing the effects of corrosion on the metallic surfaces. This AMP will provide 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 of metallic and elastomer components will be conducted. Surface examinations or ASME Code Section XI VT-1 examinations (including those inspections conducted on non-ASME Code components) will be conducted to detect cracking of copper alloy components with more than 15% Zn. Periodic visual inspections or surface examinations will be conducted to manage cracking every 10 years during the SPEO. Component surfaces that are insulated and may be exposed to condensation and insulated outdoor components will be inspected at least every 10 years or more frequently as required by plant specific OE. Surfaces that are not readily visible during plant operations and refueling outages will be inspected opportunistically when made accessible or within an interval that would ensure the components’ intended functions are maintained. Other inspections will be performed at a frequency not to exceed one refueling cycle.

For elastomers, manual and physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under the External Surfaces Monitoring of Mechanical Components AMP. Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures, including inspection parameters such as lighting, distance, offset, and surface conditions.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria will be 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 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new condition monitoring program that will manage loss of material, cracking, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of elastomeric materials. Applicable environments will include air, gas, condensation, diesel exhaust, and any water-filled systems not within the scope of other AMPs.

The AMP will consist of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, elastomeric components, and other components. Surface examinations or ASME Code Section XI VT-1 examinations will be conducted to detect cracking of in-scope titanium components. Aging effects associated with components within the scope of the Open-Cycle Cooling Water AMP, the Closed Treated Water Systems AMP, and the Fire Water System AMP will not be 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 (defined as components having the same material, environment, and aging effect combination) or a maximum of 19 components per population will be inspected at each unit. For HNP (two-unit site), where the sample size will not be based on the percentage of the population, a reduction in the total number of inspections to 19 components inspected per unit is acceptable. Site OE has not indicated a difference in aging effects between the two units for the environment and material combinations managed by this AMP.

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 be performed in each period despite meeting the sampling limit. For certain materials, such as elastomers, 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 in-scope components exposed to raw water or waste water, 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 Lubricating Oil Analysis AMP is an existing sampling program titled lubrication oil instruction. 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 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 Lubricating Oil Analysis AMP will be validated by the results of inspections completed under the One-Time Inspection AMP (A.2.2.20).

A.2.2.26 Monitoring of Neutron-Absorbing Material Other Than Boraflex

The 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 five percent sub-criticality margin in the spent fuel pool (SFP) is maintained during the period of extended operation 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.

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP elements follow the guidance in the Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP elements described in NUREG-2191, Section XI.M40.

A.2.2.27 Buried and Underground Piping and Tanks

The Buried and Underground Piping and Tanks AMP, previously known as the Underground Pipe and Tanks Monitoring 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 AMP addresses piping and tanks composed of any metallic material that are within the scope of SLR in the emergency diesel generator (EDG), FP, high pressure coolant injection (HPCI), plant service water (PSW), reactor core isolation cooling (RCIC), residual heat removal (RHR), and standby gas treatment (SBGT) systems.

This AMP also manages aging through preventive and mitigative actions (i.e., inspections, coatings, backfill quality, and cathodic protection for the emergency diesel fuel oil storage tanks). The number of inspections for each 10-year inspection period, commencing 10 years prior to the SPEO, is based on the effectiveness of the preventive and mitigative 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. Internal inspections may be performed using a method capable of precisely determining pipe wall thickness. The method must be capable of detecting both general and pitting corrosion on the external surface of the piping and must be qualified to identify loss of material that does not meet the acceptance criteria. Ultrasonic examinations, in general, satisfy this criterion. The selection of locations of the inspections of buried components is based on plant OE, risk, soil conditions, and past inspection results; these inspections will occur once prior to the SPEO and at least every 10 years during the SPEO. Opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met.

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 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be a new condition monitoring program that will manage degradation of internal coatings/linings exposed to raw water, treated water, waste water, and sodium pentaborate solution 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 CCCW, fuel oil, lubricating oil, air or condensation environment at HNP. The 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 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 (i.e., coatings specialist) 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 are not acceptable. Blisters are evaluated by a coatings specialist. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating, with blister size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, 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 ASME Section XI, Subsection IWE AMP is an existing AMP. This AMP requires visual examinations of the accessible surfaces (base metal and welds) of the drywell, torus, vent headers, penetrations, airlocks, manways and associated integral attachments. The program also requires examination of pressure retaining bolting and moisture barriers.

This program is in accordance with ASME Code Section XI, Subsection IWE, consistent with 10 CFR 50.55a “Codes and standards,” with supplemental recommendations. The AMP includes periodic visual, surface, and volumetric examinations, where applicable, of metallic pressure retaining components of the steel containment for signs of degradation, damage, irregularities, and for coated areas, and distress of the underlying metal shell. Corrective actions are implemented when required based on results. The acceptability of inaccessible areas of the steel containment shell is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

This program also includes aging management for the potential loss of material due to corrosion in the inaccessible areas of the BWR Mark I steel containment. In addition, the program includes supplemental monitoring to detect cracking for specific pressure-retaining components subject to cyclic loading that have no CLB fatigue analysis; and if triggered by plant-specific OE, a one-time supplemental volumetric examination by sampling randomly selected as well as focused locations susceptible to loss of thickness due to corrosion of containment shell that is 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 ASME Section XI, Subsection IWF AMP is an existing condition monitoring program which consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. This program recommends additional inspections beyond the inspections required by the ASME Code Section XI, Subsection IWF program. This consists of a one-time inspection of an additional five percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. This one-time inspection is conducted within five 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. The preventive actions and guidelines emphasize proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting.

Discovery of support deficiencies during regularly scheduled inspections triggers an increase in the inspection scope. Degradation that potentially compromises support function or load capacity is identified for evaluation. ASME Code Section XI, Subsection IWF specifies acceptance criteria and corrective actions. Supports requiring corrective actions are reexamined during the next inspection period. 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 10 CFR Part 50, Appendix J AMP is an existing AMP that was formerly credited for initial LR. The 10 CFR Part 50, Appendix J AMP is a performance monitoring program that monitors leakage rates through the containment system, its shell or liner, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. This program is implemented in accordance with 10 CFR Part 50, Appendix J (Option B), RG 1.163, NEI 94-01, ANSI/ANS 56.8-2002, 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. Three types of tests are performed under Option B. Type A integrated leak rate tests 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. Containment leakage rate tests are performed at frequencies in accordance with the provisions of 10 CFR Part 50, Appendix J.

A.2.2.32 Masonry Walls

The Masonry Walls AMP is an existing condition monitoring AMP consisting of inspection activities, based on inspection and enforcement bulletin (IEB) 80-11 and plant-specific monitoring proposed by information notice (IN) 87-67, to detect age-related degradation including shrinkage, separation, gaps, loss of material, and cracking for masonry walls such that the evaluation basis is not invalidated and intended functions are maintained. Masonry walls that perform a fire barrier function are also managed by the Fire Protection AMP (A.2.2.15). The Structures Monitoring AMP (A.2.2.33) monitors structural steel elements associated with masonry walls.

A.2.2.33 Structures Monitoring

The 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 that described in American Concrete Institute (ACI) 349.3R, ACI 201.1R, Structural Engineering Institute/American Society of Civil Engineers (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. Inspections are performed every five years or the next scheduled refueling outages following the five year interval in areas normally inaccessible except during outages. Inspections also include seismic joint fillers, elastomeric materials; and steel edge supports and steel bracings associated with masonry walls, and periodic evaluation of groundwater chemistry and opportunistic inspections for the condition of below-grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of degradation. The acceptance criteria are derived from applicable consensus codes and standards and are provided for each structure type and/or component inspection attribute. For concrete structures, the program includes personnel qualifications and the quantitative acceptance criteria of ACI 349.3R. Due to the presence of aggressive groundwater chemistry (pH < 5.5), the Structures Monitoring AMP includes a plant-specific enhancement to conduct a baseline visual inspection and evaluation to address the degradation of concrete due to exposure of aggressive chemical attack. The baseline evaluation will consider the baseline inspection results to determine the additional actions that are warranted. Periodic inspections, either focused or opportunistic, and evaluation updates (not to exceed five years) will be performed throughout the SPEO to ensure aging of inaccessible concrete is adequately managed.

A.2.2.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing AMP that consists of inspection and surveillance of water-control structures. The only structure in-scope of the Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is the intake structure. The trash racks, stop logs, traveling screen, and bolting associated with the intake structure are managed by this AMP. Structural steel components associated with the intake structure are managed by the Structure Monitoring AMP (A.2.2.33). 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. The groundwater at HNP is periodically monitored and evaluated.

A.2.2.35 Protective Coating Monitoring and Maintenance

The Protective Coating Monitoring and Maintenance AMP is an existing AMP that ensures monitoring and maintenance of Service Level I coatings in accordance with RG 1.54 and is adequate for the SPEO. The program consists of guidance for selection, application, inspection, and maintenance of protective coatings. The program also establishes qualifications for individuals responsible for inspecting, coordinating, and evaluating the conditions of the coatings. Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside primary containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors) serve to prevent or minimize loss of material due to corrosion of carbon steel components and aids in decontamination. Degraded coatings in the primary containment are assessed periodically to ensure post-accident operability of the emergency core cooling system (ECCS).

A.2.2.36 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, previously known as the Insulated Cables and Connections Program, is an existing AMP that provides reasonable assurance that the intended functions of accessible electrical cable insulating material (e.g., power, control, and instrumentation) and connection insulating material that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP visually inspects accessible cables and connection electrical insulation material for signs of reduced electrical insulation resistance due to an adverse localized environment (ALE) of temperature, moisture, radiation, and oxygen that includes radiolysis, photolysis (ultraviolet sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion, indicated by signs of electrical insulation embrittlement, discoloration, cracking, melting, swelling, or surface contamination. An ALE is a condition in a limited plant area that is significantly more severe than the plant design basis environment for the cable or connections insulation material that could increase the rate of aging of a component or have an adverse effect on operability. An ALE exceeds the most limiting condition for temperature, radiation, or moisture, for the electrical insulation of cables and connectors.

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 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 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP requires cable and connection insulation to be inspected for signs of degradation at least once every 10 years.

A.2.2.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits

The 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 current signals that are within scope of LR 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 10 years.

A.2.2.38 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing condition monitoring 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, pull boxes, 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 SLR are to be completed no later than 6 months prior to the SPEO with subsequent tests performed at least once every 6 years thereafter.

Periodic actions to mitigate inaccessible medium-voltage power cable exposure to significant moisture include inspection for water accumulation in cable pull boxes 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 pull boxes or vaults, are effective in preventing inaccessible medium-voltage power cable exposure to significant moisture.

Inspection of pull boxes (if equipped) with remote water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables will be performed at least once every five years.

A.2.2.39 Electrical Insulation for Inaccessible Instrumentation and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of the 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 or 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 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP applies to inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, pull boxes, or direct buried installations) I&C cables 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.

In this AMP periodic actions are taken to prevent inaccessible I&C cables from being exposed to significant moisture. Periodic actions taken to mitigate inaccessible I&C cable surface exposure to significant moisture include inspection for water accumulation in cable pull boxes/vaults and conduit ends, and removing or draining water, as needed. Inspections of the pull boxes are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR implemented 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 pull boxes or vaults, is effective in preventing inaccessible I&C cable exposure to significant moisture.

Inspection of pull boxes (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 pull box 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 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements 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 the applicable pull boxes) at least once every six years and may be coordinated with the periodic inspection for water accumulation. Inaccessible and 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 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 and underground I&C cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium- or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, construction, 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 recommended in the 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 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, pull boxes, manholes, or direct buried installations) low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of SLR that are potentially 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 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 and underground low-voltage power cable exposure to significant moisture include inspections for water accumulation in cable pull boxes/vaults and conduit ends and removing or draining water, as needed. Inspections of the pull boxes are performed periodically based on water accumulation over time. The periodic inspections occur at least once annually with the first inspections for SLR to be implemented prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice or snow, and 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 pull boxes or vaults, is effective in preventing inaccessible low-voltage power cable exposure to significant moisture.

In addition to inspecting for water accumulation, visual inspections will be performed for low-voltage cables that are accessible during pull box 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 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 during the SPEO 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, testing of abandoned or removed cables, or testing of 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 by this AMP.

A.2.2.41 Fuse Holders

The Fuse Holder AMP is a new inspection program that manages fuse holders located inside passive electrical enclosures that perform a LR intended function. The program focuses on the metallic clamp portion of the fuse holder. Fuse holders are considered susceptible to the following aging effects: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement, or vibration. This AMP also manages degradation of electrical insulation for the fuse holders that have metallic clamps that are susceptible to the aging effect identified. Fuse holders inside an active device (e.g., switchgear, power supplies, inverters, battery chargers, and circuit boards) and not subject to the aging effects identified are not within the scope of this AMP.

Visual inspections of in-scope fuse holders will be performed prior to the SPEO and on a frequency of once every 10 years during the SPEO. The metallic clamp portion of the fuse holder is tested to detect any increased resistance of the connection due to chemical contamination, corrosion, and oxidation. The metallic clamp is also inspected for fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement or vibration. The metallic clamp portion will be tested via thermography or contact resistance testing. The testing of the metallic clamp will occur at least once every 10 years during the SPEO, with the first test to be performed prior to SPEO. The electrical insulation material portion of the fuse holder is visually inspected to identify insulation surface anomalies, indicating signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis and photolysis (UV-sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion as indicated by signs of embrittlement, discoloration, cracking, melting, swelling, or surface contamination.

A.2.2.42 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new 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 of the connection are maintained consistent with the CLB through the SPEO.

This AMP manages the aging mechanisms and effects associated with the metallic portion of electrical connections that result in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation such that the metallic portions of electrical cable connections are maintained consistent with the CLB through the SPEO.

This AMP focuses on the metallic parts of the electrical cable connections. One-time testing, on a sample basis, will confirm the absence of age-related degradation of cable connections resulting in increased resistance of the connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation. 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 EQ program are not included in the scope of this AMP.

A representative sample of cable connections within the scope of SLR are tested on a one-time test basis to confirm the absence of age-related degradation of the cable connection. Initial one-time test findings will document unacceptable conditions or degradation identified and whether they were determined to be age-related thereby requiring subsequent testing on a 10-year basis. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. 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 within 10 years of the initial testing. The following factors are considered for sampling: voltage level (medium and low), 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. Otherwise, a technical basis will be given on the method and sample size of components utilized and will be documented as part of this program. The one-time tests for SLR are to be completed prior to the SPEO.

A.2.2.43 High-Voltage Insulators

The High-Voltage Insulators AMP is a new AMP that provides reasonable assurance that the intended functions of high-voltage insulators within the scope of SLR are maintained consistent with the CLB through the SPEO. The High-Voltage Insulators AMP was developed specifically to manage aging of high-voltage insulators susceptible to aging degradation due to local environmental conditions. This AMP is applicable to different types of high-voltage insulators such as porcelain, toughened glass, and polymer.

The High-Voltage insulators AMP will be a condition monitoring program that relies on visual inspections and high-voltage insulator cleaning, and optional coating, to manage high-voltage insulator aging effects. High-voltage insulator periodic visual inspections are performed to monitor the buildup of contaminants on the insulator surface. The periodic coating or cleaning of high-voltage insulators limits high-voltage insulator surface contamination.

The program includes the inspection of the high-voltage insulators within the scope of this program to identify degradation of high-voltage insulator sub-component parts, namely, the insulation and metallic elements. Visual inspection provides reasonable assurance that the applicable aging effects are identified, and high-voltage insulator age degradation is managed. Insulation materials used in high-voltage insulators may degrade more rapidly than expected when installed in an environment conducive to accelerated aging. The insulation and metallic elements of high-voltage insulators are made of porcelain, cement, malleable iron, aluminum, polymer, and galvanized steel. The most common type of high-voltage insulators used throughout switchyards, transmission lines, and power systems are porcelain. However, polymer and toughened glass high-voltage insulators are also found in some installations and are included in this AMP. Polymer high-voltage insulators are typically composed of material such as fiberglass, silicone rubber (SiR), ethylene propylene rubber (EPR), epoxy, silicone gel, sealants, ductile iron, aluminum, aluminum alloys, steel, steel alloys, malleable iron, and galvanized metals. Exposure to air-outdoor can cause degradation and aging effects that can result in reduced insulation resistance due to deposits and surface contamination, reduced insulation resistance due to polymer degradation as well as loss of material caused by wind blowing on transmission conductors, and loss of material due to corrosion, all of which may require aging management. Polymer high-voltage insulators have been shown to have unique failure modes with minimal advance indications. Surface buildup of contamination can be worse for SiR (compared to porcelain insulators) due to absorption by silicone oil, especially in late stages of service life.

The high-voltage insulators within the scope of this program are to be visually inspected at a frequency based on plant-specific OE with the specific type of insulator used (i.e., porcelain, polymer, toughened glass). Periodic coating and/or cleaning of the high-voltage insulators is also included as part of the program (with the frequency determined by site OE). The first inspections are to be completed prior to the SPEO.

A.2.3 Plant Specific Aging Management Programs

This section provides FSAR summaries of the plant specific AMPs credited for managing the effects of aging.

A.2.3.1 RHR Heat Exchanger Augmented Inspection

The RHR Heat Exchanger Augmented Inspection AMP is an existing AMP that inspects, tests, and cleans passive components of the RHR heat exchangers to mitigate flow blockage, prevent reduction of heat transfer and loss of material. The objective of the program is to assure that no unacceptable degradation is occurring. The RHR Heat Exchanger Augmented Inspection and Testing AMP is a condition monitoring program that manages aging of the RHR heat exchangers.

There are two RHR heat exchangers per unit. The RHR Heat Exchanger Augmented Inspection and Testing AMP applies cleaning, visual inspection and eddy current testing in accordance with plant procedures. The program partially satisfies the requirements of NRC GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment” and incorporates the guidance of Department of Energy (DOE) report, SAND 93-7070.UC-523, "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers" as supplemented by reviews of current industry experience and practice, as the basis for this program.

The RHR Heat Exchanger Augmented Inspection and Testing AMP requires that heat exchanger tubes and channel interior be cleaned on an 8-year frequency. This cleaning of the heat exchanger tubes, and channel head mitigates flow blockage and prevents reduction of heat transfer.

The RHR Heat Exchanger Augmented Inspection and Testing AMP provides for visual inspections of channel side (including partition plate and tube sheet) and tube interior. This activity detects loss of material, and flow blockage. The shell side of the tube sheets, shell internals, and impingement plates are visually inspected at an 8-year frequency, where accessible. Although, the visual inspection frequency may be changed based on the trend and engineering evaluation. The inspection focuses on tube interfaces, tie rods or fasteners, and accessible welds. This activity detects loss of material, and flow blockage (fouling).

Eddy current testing is performed at least once (for each RHR heat exchanger) during each 8-year inspection interval and whenever leaks are suspected. Testing is performed by qualified personnel and include accessible portions of the straight tube sections and U-bends of the test sample. This activity detects loss of material. Eddy current testing includes examination of at least ten percent of the non-plugged tubes in each RHR heat exchanger tube bundle.

Tube and tube sheet leak testing or inspection is performed whenever leaks are suspected. This activity detects leaks due to loss of material. Inspection and testing results are maintained in plant records and engineering personnel track and trend results in accordance with plant procedures.

Any unacceptable indication of loss of material is evaluated by engineering. When appropriate, engineering evaluations are based upon the design code of record. If warranted, additional inspections are performed. Any significant degradation of components inspected by the RHR Heat Exchanger Augmented Inspection and Testing AMP is noted and corrective actions are implemented in accordance with the existing corrective actions program.

A.2.3.2 Torus Submerged Components Inspection

The Torus Submerged Components Inspection Program is an existing condition monitoring program that monitors SSCs submerged within the suppression pool and in the vapor space directly above the suppression pool for loss of material and cracking. The vapor space is the location at or just above the suppression pool water line where it is more susceptible to corrosion due to the effects of alternate wetting and drying (splash zone). The objective of the program is to assure that no unacceptable degradation is occurring. This inspection is intended to validate the adequacy of suppression pool chemistry controls to manage aging effects for a variety of uncoated SCs that are exposed to the suppression pool environment.

Torus submerged components inspections are conducted on accessible components submerged in suppression pool water, including the emergency core cooling system (ECCS) pump suction strainers and the RCIC pump suction strainer. The submerged portion of the safety relief valve (SRV) and vacuum relief piping is also included, as is the low carbon steel, Non-Class 1 piping. Baseline examinations for this program were performed prior to entering the PEO to examine a sample set of the uncoated components in the torus within the scope of LR. This sample was biased towards the areas most likely to exhibit corrosion related degradation such as weld heat affected zones and crevices. The results of the initial inspections were used to determine ongoing inspection scope and frequency. These inspections will continue throughout the SPEO.

Detailed visual inspections for evidence of microbiologically influenced corrosion (MIC), pitting or crevice corrosion, or similar mechanisms are performed on the in-scope components. Visual inspections are conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210, or other suitable method as dictated by the component configuration. Specific inspection criteria, inspection techniques, and acceptance criteria are contained in the inspection procedure(s).

Any unacceptable indication of loss of material or cracking is evaluated by engineering. When appropriate, engineering evaluations are based upon the design code of record. If warranted based upon the results of the initial inspections, inspections of additional locations within the torus are performed. Corrective actions are implemented in accordance with the corrective actions program.

A.3 TIME-LIMITED AGING ANALYSIS

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.3.7.2 and are evaluated per the requirements of 10 CFR 54.21(c).

A.3.1 Identification of Time-Limited Aging Analyses and 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 and the HNP Units 1 and 2 FSARs 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. There are no 10 CFR 50.12 exemptions involving TLAAs as defined in 10 CFR 54.3 identified for the SPEO.

Fatigue waivers for ASME Class 1 components are documented in Section A.3.3.2. Additionally, a fatigue exemption analysis of the backing ring for the HNP Unit 1 main steam containment penetrations and for the HNP containment and containment penetrations is included in Section A.3.6.2. However, these are not 10 CFR 50.12 exemptions.

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 50, Appendices G and H. The 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 TLAAs concerns the effect of irradiation embrittlement (IE) on the beltline and extended beltline regions of the HNP Unit 1 and Unit 2 reactor vessels, 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 TLAAs, 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 Upper Shelf Energy (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)
- Susceptibility to IASCC (Section A.3.2.8)

A.3.2.1 Neutron Fluence Projections

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter that contact the RVI 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 HNP Unit 1 is 68.6 EFPY and for Unit 2 is 66.0 EFPY.

Updated fluence projections were developed for 80 years of plant operation, based upon 68.6 EFPY and 66.0 EFPY for Units 1 and 2 respectively, for use as inputs to updated neutron embrittlement analyses for the SPEO. These EFPY fluence projections were developed using methodologies that follow the guidance of NRC RG 1.190 and are consistent with the NRC approved RAMA methodology. The 68.6 EFPY for Unit 1 and 66.0 EFPY for Unit 2 fluence projections have been determined for reactor vessel beltline and extended beltline materials, which include all reactor vessel welds, shell plates, and nozzles 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 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 A.2.1.3 and A.2.2.19, respectively.

A.3.2.2 RPV Materials Upper Shelf Energy (USE) Reduction Due to Neutron Embrittlement

USE is the parameter used to indicate the maximum impact toughness of a material at high temperature. Neutron embrittlement reduces the USE value below its initial value.

10 CFR 50, Appendix G, Paragraph IV.A.1.a, requires the predicted End of Life (EOL) USE for RPV materials to be at least 50 ft-lbs. (absorbed energy) unless an approved equivalent margin analysis (EMA) supports a lower value.

The current HNP Unit 1 and Unit 2 licensing basis USE calculations were updated with fluence projections to the end of the SPEO, which is 68.6 EFPY for Unit 1 and 66.0 EFPY for Unit 2. The latest revision of BWRVIP-135 is reviewed for any information from the EPRI BWRVIP ISP that is applicable to HNP and is utilized in this evaluation. Since the USE value is a function of neutron fluence that 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 that require evaluation for the 80-year SPEO.

EMA is used for all HNP Unit 1 beltline materials lacking unirradiated USE values due to their unavailability. The EMA is performed for the limiting USE beltline plate and weld materials for HNP Unit 1. The current EMA analysis conservatively uses the existing acceptance criteria defined in BWRVIP-74-A which are the maximum allowable percent decrease in USE for the BWR/3-6 plates and BWR/2-6. The HNP Unit 2 USE is evaluated per initial unirradiated USE values in accordance with RG 1.99 using the equations in RG 1.162.

The results demonstrate that EOL USE values for HNP Units 1 and 2 at 68.6 and 66 EFPY respectively, remain bounded by the maximum allowed decrease in USE by BWRVIP-74-A or the 10 CFR 50 Appendix G criteria of at least 50 ft-lbs. through EOL. EMA evaluation will remain within the limits of RG 1.99 and satisfy the margin requirements of safety against fracture, equivalent to 10 CFR 50 Appendix G requirements.

Therefore, the USE 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

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 pressure-temperature 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. Since the ΔRT_{NDT} value is 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.

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 currently licensed P-T limit curves are located in the P-T Limits Reports (PTLRs) for both Unit 1 and Unit 2. The Technical Specification Limiting Condition for Operation (LCO) 3.4.9 states that the reactor coolant system (RCS) pressure, temperature, heatup and cooldown rates, and recirculation pump starting temperature shall be maintained within the limits specified in the PTLRs. 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 49.3 EFPY for Unit 1 and 50.1 EFPY for Unit 2.

HNP Unit 1 and Unit 2 Technical Specification 5.6.7(c) requires that the PTLR be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement. Prior to exceeding the current limits, new P-T limit curves will be generated to cover plant operation to 68.6 EFPY for Unit 1 and 66.0 EFPY for Unit 2, and a PTLR change request will be submitted to the NRC.

The Reactor Vessel Material Surveillance AMP (A.2.2.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC prior to exceeding the current terms of applicability in the Technical Specifications for HNP.

Therefore, the P-T limits TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.2.5 RPV Circumferential Weld Examination Relief

EPRI TR-105697 (BWRVIP-05) 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. Section 4.6.3 of the HNP initial LRA provided a basis for use of EPRI TR-105697 (BWRVIP-05) as a technical alternative for volumetric examination through the first LR period.

Subsequently, BWRVIP-329-A-NP 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. The HNP assessments are based on 68.6 EFPY for Unit 1 and 66.0 EFPY for Unit 2 fluence values associated with 80 years of operation and have therefore been identified as TLAAs requiring evaluation for the SPEO.

BWRVIP-329-A-NP provides criteria for applicability based on plant-specific data. Evaluation using these criteria confirmed that the HNP Unit 1 and Unit 2 RPV dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A-NP.

Using plant-specific data for the RPV dimensions and limiting ARTs for the RPV plates and welds, the evaluation shows that the HNP Unit 1 and Unit 2 RPVs meet the applicability criteria of BWRVIP-329-A-NP for up to 80 years of plant operation.

These analyses will be managed in accordance with 10 CFR 54.21(c)(1)(iii) through the SPEO 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 RPV shell welds in EPRI TR-105697 (BWRVIP-05) 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 HNP Units 1 and 2, they are identified as TLAAs requiring evaluation through the SPEO.

BWRVIP-329-A-NP and the associated NRC SER provide a 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-NP provides criteria for applicability based on plant-specific data. Evaluation for applicability to

HNP Units 1 and 2 confirms that the RPV dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A-NP.

Using plant-specific data for the RPV dimensions and limiting ARTs for the RPV plates and welds, the evaluation shows that the HNP Unit 1 and Unit 2 RPVs meet the applicability criteria of BWRVIP-329-A-NP for up to 80 years of plant operation.

Therefore, the reactor vessel axial weld failure probability analyses have 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

10CFR50 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 BWRs, this requirement is historically demonstrated both by development of Pressure-Temperature 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 LOCA event.

Reflood thermal shock of the RPV is part of the CLB for HNP. The analysis performed to demonstrate adequate margin against non-ductile failure for both Units 1 and 2 must be updated for operation up to 80 years, or 68.6 EFPY for HNP Unit 1 and 66 EFPY for HNP Unit 2. Thus, this meets the criteria of 10 CFR 54.3(a) and has been identified as a TLAA that requires evaluation for the 80-year SPEO.

For all beltline materials, a bounding evaluation was performed in which the limiting stresses and material properties for the HNP Unit 1 and Unit 2 RPVs were used. The beltline shells (plates and welds) were analyzed. To be consistent with previous analyses, RPV integrity is assured by fracture mechanics analyses of the limiting vessel locations to show that no crack initiation would occur under these LOCA transient conditions for the SPEO. The limiting 0T ART for beltline materials is 152.1°F at 68.6 EFPY for Unit 1 and 89.3°F at 66 EFPY for Unit 2.

The maximum crack driving force, $K_{Iapplied}$, in the vessel at any time during the main steam line break LOCA transient is 105 ksi-in$^{1/2}$. Therefore, the maximum crack driving force is less than the allowable value by a 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 105 ksi-in$^{1/2}$. A maximum K_I of 105 ksi-in$^{1/2}$ was utilized per the thermal shock analysis. The acceptability of this K on a plant-specific basis for HNP Unit 1 and Unit 2 can be determined by considering a revised allowable fracture toughness applicable to the HNP Unit 1 and Unit 2 vessels for 68.6 EFPY and 66.0 EFPY, respectively. Based on a 0T ART of 152.1°F for Unit 1, and 89.3°F for Unit 2, the fracture toughness K_{IC} of 256.0°F and 311.2°F for Units 1 and 2 respectively, is above the upper shelf value of 200 ksi-in$^{1/2}$.

The bounding stress intensity factor, K, for HNP Unit 1 and Unit 2 of 105 ksi-in$^{1/2}$ is less than the available fracture toughness of 200 ksi-in$^{1/2}$ after 68.6 EFPY for Unit 1 and 89.3°F at 66.0 EFPY for Unit 2, which provides an acceptable result for thermal shock of the vessel reflood from a main steam line break LOCA.

The RPV reflood thermal shock analysis has been projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.3.2.8 Susceptibility to IASCC

Appendix C of the HNP LRA states that one of the conditions required for the initiation of IASCC and embrittlement in austenitic stainless steel reactor internals is a fluence exceeding ~3-5 x 10^{20} n/cm^2 E>1.0 MeV. HNP's LRA did not identify IASCC as a TLAA, stating that there is only a small set of near core internals that exceed the neutron fluence threshold required to render a component susceptible to IASCC. However, calculations that are an input to determine IASCC susceptibility for fluence greater than 5 x 10^{20} n/cm^2 E>1.0 MeV are TLAAs that require evaluation for the SPEO.

Fluence values for the Unit 1 and Unit 2 jet pump components, core shrouds, top guides, instrument dry tubes, instrument guide tubes, and core support plates are projected to exceed the threshold of 5.0x10^{20} n/cm2 before the end of the SPEO. Per BWRVIP-315, the instrument dry tubes and instrument guide tubes do not require inspections, and the core support plate does not have aging effect requiring management through the SPEO.

Therefore, the core shroud, top guide, and jet assembly components will be inspected periodically for IASCC and loss of fracture toughness (embrittlement) throughout the SPEO.

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 AMP (A.2.2.7), 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 HNP. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the FSAR. Fatigue analyses are considered TLAAs 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 (A.3.3.1)
- ASME Section III, Class 1 Fatigue Waivers (A.3.3.2)
- RPV Fatigue Analyses (A.3.3.3)
- Fatigue Analysis of RPV Internals (A.3.3.4)
- ASME Section III, Class 1 Fatigue Analysis (A.3.3.5)

- ASME Section III, Class 2 and 3 and ANSI B31.1 and Associated HELB Analyses (A.3.3.6)
- Environmentally-Assisted Fatigue (A.3.3.7)
- High Energy Line Break Analyses Based on Cumulative Fatigue Usage (A.3.3.8)
- Cycle-dependent Fracture Mechanics or Flaw Evaluations (A.3.3.9)

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 various 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 CUF and 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 and are acceptable for all locations for both HNP Unit 1 and Unit 2.

A.3.3.2 ASME Section III, Class 1 Fatigue Waivers

Original components of the HNP Unit 1 RPV were designed to the ASME Boiler and Pressure Vessel Code, 1965 Edition with Addenda through Winter 1966. Unit 2's original components were designed to the ASME Boiler and Pressure Vessel Code, 1968 Edition with Addenda through Summer 1970.

The design stress reports for the HNP Unit 1 and Unit 2 RPVs include fatigue waivers that determined that various RPV structural components such as nozzles, brackets, or lifting lugs for each unit did not require explicit fatigue analyses because the waiver criteria from ASME Section III, Paragraph N-415.1 was satisfied. The fatigue waiver evaluations are TLAAs and were re-evaluated 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 the effects of 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 Fatigue Monitoring AMP (A.2.1.2) 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. The ASME Code, Section III, Class 1 component fatigue waivers will be adequately managed by the Fatigue Monitoring AMP (A.2.1.2) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.3.3 RPV Fatigue Analyses

The HNP Unit 1 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 1966 Winter Addenda) for Class 1 design requirements. The

HNP Unit 2 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 Summer 1970 Addenda) for Class 1 design requirements.

These 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 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 HNP Unit 1 and Unit 2 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 (A.2.1.2) 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 HNP's first license renewal using the ASME Boiler and Pressure Vessel Code, Section III methodology. 80-year fatigue projections were performed for all monitored locations and then screened based on bounding fatigue usage values from available fatigue analyses, which are scaled for 80 years and EPU as applicable. The largest scaled fatigue usage for Unit 1's monitored RPV/RVI locations occurs at the CRD nozzles' stub tube to bottom head juncture. For Unit 2, the largest scaled fatigue usage for the monitored RPV/RVI locations occurs at the instrument/head spray nozzle bolts. These locations are bounding for all other Unit 1 and Unit 2 RVI fatigue affected components.

For all locations where usage was recalculated, the design and 80-year projected fatigue usages are less than 1.0 and are therefore acceptable. The effects of fatigue on the intended functions of the RVI will be managed by the Fatigue Monitoring AMP (A.2.1.2) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.3.5 ASME Section III, Class 1 Fatigue Analysis

HNP Unit 1 piping systems were originally designed in accordance with USAS B31.7; HNP Unit 2 piping systems were originally designed in accordance with Section III, NB, 1971. These design codes require an evaluation of the predicted fatigue CUF for the Class 1 components. The ASME Code requires that the Class 1 components have an initial design predicted CUF less than or equal to 1.0.

Existing fatigue reports and 80-year cycle projections are used to calculate projected 80-year fatigue usage for the locations within the scope of the HNP Class I piping. If needed, fatigue is adjusted for extended power uprate (EPU) based on changes to temperature, pressure, and flow rate. Fatigue usage is calculated using B31.7/ASME Section III, 1970 Addenda, NB-3653.6(c) Code methodology for piping.

The fatigue analyses and corresponding CUF for HNP Unit 1 and Unit 2 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 (A.2.1.2) 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 and Associated HELB Analyses

The HNP Unit 1 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 ASME B31.7 and ANSI B31.1 Codes. The HNP Unit 2 non-Class 1 RCS piping and balance-of-plant piping systems within the scope of SLR are designed to the requirements of ASME Section III and B31.1 codes. ASME B31.7 defers to ANSI B31.1 for non-Class 1 components and ASME Section III Code Class 2 and 3 components are designed to requirements that are similar to the guidance in ANSI B31.1.

HNP's construction codes did not require an explicit analysis of cumulative fatigue usage for non-Class 1 piping and components, however, a stress range reduction factor was applied to the allowable stress range to account for cyclic thermal conditions. The 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 the 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 ASME III and ANSI B31.1 piping within the scope of SLR was performed 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. The initial LR TLAA report and P&IDs were used to identify affected systems for this evaluation.

In addition, the HNP Unit 1 FSAR, Appendix N Section N.4.1.1 states that postulated pipe breaks were evaluated for high-energy lines outside of primary containment. These lines were postulated per Atomic Energy Commission (AEC) criteria and pipe cracks at the most adverse locations. In accordance with AEC Criterion 2, circumferential and/or longitudinal breaks have been assumed to occur at the following locations in each piping run or branch run at terminal ends and any intermediate locations between terminal ends where either the circumferential or longitudinal stresses derived on an elastically calculated basis under the loadings associated with seismic events and operation plant conditions exceed 0.8 $(1.2\ S_h + S_A)$ or the expansion stresses exceed 0.8 S.

The current fatigue design criteria remain valid with significant margin for the 80-year SPEO. Therefore, all of these systems at HNP Unit 1 and Unit 2 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 Environmentally-Assisted Fatigue

The effects of the reactor water environment on CUF_{en} are examined for a set of sample critical components for HNP Units 1 and 2. These critical components 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 environmental fatigue correction factor (F_{en}) values based on material type, maximum temperature, maximum sulfur content (for carbon steel and low alloy steel), minimum strain rate, and dissolved oxygen, bounding CUF_{en} is estimated for all locations. Locations that have bounding $CUF_{en} < 1.0$ 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 HNP Unit 1 were seventeen (17) sentinel locations analyzed with all locations projected to be below the allowable CUF_{en} value of 1.0 at 80 years of operation. The results for HNP Unit 2 were seventeen (17) sentinel locations analyzed with no locations projected to be above the allowable CUF_{en} value of 1.0 at 80 years of operation.

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 (A.2.1.2) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.3.8 High Energy Line Break Analyses Based on Cumulative Fatigue Usage

The HNP Unit 1 and Unit 2 HELB analyses used the CUF values from the ASME Class 1 fatigue analyses as input in determining intermediate break locations. The licensing basis pipe break criteria required that breaks be postulated at piping locations where the calculated CUF exceeded 0.1. Locations with a design CUF value less than or equal to 0.1 did not require an intermediate break to be postulated. Because the HELB analyses are based on the Class 1 piping fatigue TLAAs that provided the CUF values, they are considered potential TLAAs for the SPEO.

FatiguePro 3 was used to determine the overall effect of the cumulative numbers of transient cycles that have occurred at a given time and determines the CUF values resulting from the combination of transient cycles that have occurred. The 80-year projected cycle and fatigue usage was calculated as below the allowable limit for the Unit 1 SBLC piping and the Unit 2 feedwater and reactor water cleanup (RWCU) piping.

The Fatigue Monitoring AMP (A.2.1.2) monitors and tracks the number of critical thermal, pressure, and seismic transients to ensure that the CUF and CUF_{en} for each analyzed component are adequately managed such that they do not exceed the applicable limit through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.3.9 Cycle-dependent Fracture Mechanics or Flaw Evaluations

HNP Unit 1 2020 refueling outage UT identified one flaw indication in the RPV closure head dollar plate weld. The flaw in weld HC-1 exceeded the acceptance standards of ASME Boiler and Pressure Vessel Code Section XI IWB-3510. GE Hitachi Nuclear Energy prepared a fracture mechanics evaluation of the indication to determine the acceptability of the dollar plate weld indication through the SPEO.

The fracture mechanics evaluation for the dollar plate weld's indication was performed in accordance with ASME Section XI, IWB-3600 and the flaw evaluation procedure described in ASME Section XI, Appendix A. The transients listed in the original Combustion Engineering stress report were reviewed and the stresses were updated considering current operating conditions, including the power uprates. The fatigue crack growth through 80 years was determined to be within limits and meets the fracture mechanics requirements specified in ASME Section XI, IWB-3612. Based on this evaluation, the subject indication detected in the HNP Unit 1 RPV closure head dollar plate weld is acceptable through the SPEO per the flaw acceptance criteria of ASME Section XI and in accordance **10 CFR 54.21(c)(1)(ii)**.

A.3.4 Environmental Qualification (EQ) of Electric 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 a 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 EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a LOCA, HELB, or post-LOCA radiation. 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 EQ AMP that specify a qualification of at least 60 years have been identified as a TLAA for LR because the EQ aging evaluations meet the criteria in 10 CFR 54.3.

The Environmental Qualification of Electric Equipment AMP (A.2.1.1) 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 AMP, 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 not qualified for the current license term prior to the end of designated life unless additional life is

established through 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 (DOR) Guidelines, NUREG-0588, and NRC RG 1.89, Revision 1.

The Environmental Qualification of Electric Equipment AMP (A.2.1.1) will manage the effects of aging for the components associated with the EQ TLAA. This AMP implements the requirements of 10 CFR 50.49 and RG 1.89, Rev. 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 Environmental Qualification of Electric Equipment AMP (A.2.1.1) provides reasonable assurance that the applicable aging effects will be managed such that safety-related electrical equipment in harsh environments will continue to perform their intended functions consistent with the CLB throughout the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.5 Concrete Containment Tendon Prestress

The HNP Unit 1 and Unit 2 containments do not have pre-stressed tendons. As such, concrete containment tendon prestress is not a TLAA.

A.3.6 Containment Liner Plate, Metal Containments and Penetrations Fatigue Analyses

The HNP Unit 1 primary containment was designed to the Class B requirements of the ASME Code, Section III, 1968 Edition with addenda through Summer 1968. The HNP Unit 2 primary containment was designed to the Class MC requirements of the ASME Code, Section III, 1971 Edition with addenda through Summer of 1971.

80-year fatigue projections have been performed for all monitored locations. Screening was performed based on bounding fatigue usage values from available fatigue analyses, which were scaled for 80 years, and EPU as applicable to determine whether additional locations should be monitored. The existing fatigue analyses of suppression chamber locations were revised to incorporate 80-year transient cycle projections. For any location with a resulting fatigue usage greater than 1.0, a detailed fatigue analysis was performed using existing fatigue tables and 80-year cycle projections.

Primary containment structural fatigue evaluations are documented in the following sections:

- Fatigue Analysis of the Vessel Shell to Ring Girder (A.3.6.1)
- Fatigue Exemption (Waivers) for Main Steam Penetration Backing Ring and Containment Penetrations (A.3.6.2)

A.3.6.1 Fatigue Analysis of the Vessel Shell to Ring Girder

The existing fatigue analyses of suppression chamber locations were revised to incorporate 80-year transient fatigue cycle projections. Projections were performed for all monitored locations. Screening was performed based on bounding fatigue usage values from available fatigue analyses, which are scaled for 80 years, and EPU as applicable to determine whether additional locations should be monitored. The screening is performed using validated FatiguePro 3 software and is based on previous fatigue updates and plant data and events for the current period. For any location with a resulting fatigue usage greater than 1.0, a detailed fatigue analysis was performed using existing fatigue tables and 80-year cycle projections.

The bounding fatigue location for both the Unit 1 and Unit 2 suppression chamber locations is the torus vessel shell at the ring girder or saddle/shell intersection. Because the projected fatigue usage for 80 years is less than 1.0 for all monitored locations, there are no additional locations that screen in.

The fatigue analyses and corresponding CUF for HNP Unit 1 and Unit 2's suppression chamber locations will remain less than 1.0 and thus are acceptable through the SPEO. The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (A.2.1.2) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.6.2 Fatigue Exemption (Waivers) for Main Steam Penetration Backing Ring and Containment Penetrations

Because HNP Unit 1's containment was designed to the Class B requirements of the 1968 Edition of the ASME Code, Section III, with Addenda through Summer 1968, a fatigue or fatigue exemption analysis is required for the backing ring for the HNP Unit 1 main steam containment penetrations. The effects of 80-year projected cycles are included. In accordance with the rules of N-415.1 of Section III of the ASME Code, the backing ring for the Unit 1 main steam containment penetrations is exempt from fatigue analysis for an 80-year life.

The ASME III 1968 Class B and 1971 Class MC codes require that a fatigue or fatigue exemption analysis be performed for the HNP containment and containment penetrations for which there are no existing calculations. This includes the primary containment (drywell), secondary containment (torus or suppression chamber), and containment penetrations. In accordance with ASME III, the containment and containment penetrations for HNP Units 1 and 2 are exempt from fatigue analysis for an 80-year life.

The fatigue analyses of the backing ring for Unit 1 main steam containment penetrations and for the containment and containment penetrations fatigue waivers will be managed by the Fatigue Monitoring AMP through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**. The Fatigue Monitoring AMP (A.2.1.2) 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.3.7 Other Plant-Specific TLAAs

A.3.7.1 Fatigue of Cranes (Crane Cycle Limits)

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 the Unit 1 reactor building overhead crane, the Unit 1 turbine building crane, and the Unit 2 turbine building crane as measured in load cycles is identified as a TLAA for SLR. The Unit 2 reactor building crane is not in scope for SLR. The Unit 1 reactor building crane is used for all Unit 2 reactor work requiring lifts greater than 50% of capacity over safety related components.

These three cranes comply with the intent of CMAA-70, “Specifications for Electric Overhead Traveling Cranes,” meet the requirements of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," Guideline 7, and are in scope of SLR. Because CMAA-70 specifies a design load cycle limit which provides a basis for acceptability of fatigue over the life of these cranes, these analyses are considered TLAAs that must be evaluated for the SPEO.

The HNP SLR Crane Fatigue TLAA Evaluation states that this TLAA will only evaluate loads greater than 50% of the three subject cranes’ capacity and that any load below 50% of their rated capacity has no effect on the life expectancy of the crane. The total projected load cycles for the Unit 1 reactor building crane through the 80-year SPEO is estimated to be 4840 lifts. The total projected load cycles for the Unit 1 and Unit 2 turbine building cranes through the 80-year SPEO are 492 and 490 lifts respectively. The projected number of load cycles for the three subject cranes is significantly less than the CMAA-70 limiting value of 20,000 cycles.

The Unit 1 reactor building overhead crane, the Unit 1 turbine building crane, and the Unit 2 turbine building crane load cycles are projected to be less than the allowable load cycles through the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

A.3.7.2 Corrosion Allowance Calculations

The HNP design made an allowance for corrosion in determining the appropriate thickness for pressure retaining components. Only those analyses containing an assumption of a corrosion allowance that also tied the allowance to a 40-year or 60-year operating life meet 10 CFR 54.3 Criterion 3 for TLAAs. In the review of the HNP analyses, the equipment designed and supplied by both Bechtel and General Electric (GE) is included in the SLRA review.

While evaluating the residual heat removal service water system piping and the plant service water system piping in accordance with NRC GLs 89-13 and 90-05, Bechtel used the corrosion allowance to predict the expected pipe thickness and to develop the minimum acceptable as-found thickness of the pipe. Much of this piping is in-scope for LR. Bechtel developed evaluation levels to measure the piping based in part upon the expected thickness of the pipe and its predicted wear for its remaining service life; these levels are considered TLAAs.

GE used a time-dependent corrosion rate to calculate the HNP Units 1 and 2 corrosion allowance for the reactor vessels based upon a 40-year assumed vessel service life. This corrosion allowance was determined to meet all six criteria and is thus a TLAA. The corrosion allowance was based upon a 40-year assumption for the service life of the vessel, and thus is a TLAA.

The Open-Cycle Cooling Water System AMP (A.2.2.11) will continue to manage the effects of aging (corrosion) for the Bechtel designed and supplied equipment through the SPEO in accordance with existing maintenance and surveillance procedures in accordance with 10 CFR 54.21(c)(1)(iii).

The Water Chemistry AMP relies on monitoring and control of reactor water chemistry based on industry guidelines to manage loss of material due to corrosion and mitigate cracking due to SCC and related mechanisms. The AMP provides reasonable assurance that these aging effects will be managed such that the reactor systems' austenitic stainless-steel components and general piping will continue to perform their intended functions consistent with the CLB throughout the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

The One-Time Inspection AMP verifies the effectiveness of the Water Chemistry AMP. It identifies and evaluates the aging effects of components in the Water Chemistry AMP for loss of material due to corrosion, and cracking due to SCC. The One-Time Inspection AMP provides reasonable assurance that the applicable aging effects will be managed such that the in scope SSCs will continue to perform their intended functions consistent with the CLB throughout the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.4 SLR Implementation Actions List

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
1	Environmental Qualification of Electric Equipment (A.2.1.1)	X.E1	Continue the existing Environmental Qualification of Electric Equipment AMP, including enhancements to: a) Include monitoring or inspection of certain environmental conditions, including ALEs, or equipment parameters to verify that the equipment is within the bounds of its qualification basis, or as a means of modifying the qualified life. b) Visually inspect accessible, passive EQ equipment at least once every 10 years with the first periodic visual inspection being performed prior to the SPEO. c) Document within the visual inspections that accessible passive EQ equipment is free from unacceptable surface abnormalities that may indicate age degradation. d) Enhance procedures to 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 the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the 10-year interval inspections no earlier than 10 years prior to the SPEO.
2	Fatigue Monitoring (A.2.1.2)	X.M1	Continue the existing Fatigue Monitoring AMP, including enhancements to: a) Update plant procedure(s) to provide procedural direction to require periodic validation of chemistry parameters that are used as inputs to determine F_{en} factors. b) Update the Fatigue Monitoring AMP governing procedure to identify and require monitoring of the 80-year plant design cycles,	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			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) The procedure governing the Fatigue Monitoring AMP will be enhanced to specify that for CUF_{en} analyses, scope expansion includes consideration of other locations with the highest expected CUF_{en} values.	
3	Neutron Fluence Monitoring (A.2.1.3)	X.M2	Implement the new Neutron Fluence Monitoring AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
4	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.2.1)	XI.M1	Continue the existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.:

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
				Unit 1: 02/06/2034 Unit 2: 12/13/2037
5	Water Chemistry (A.2.2.2)	XI.M2	Continue the existing Water Chemistry AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
6	Reactor Head Closure Stud Bolting (A.2.2.3)	XI.M3	Implement the new Reactor Head Closure Stud Bolting AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
7	BWR Vessel ID Attachment Welds (A.2.2.4)	XI.M4	Continue the existing BWR Vessel ID Attachment Welds AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
8	BWR Stress Corrosion Cracking (A.2.2.5)	XI.M7	Continue the existing BWR Stress Corrosion Cracking AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
9	BWR Penetrations (A.2.2.6)	XI.M8	Continue the existing BWR Penetrations AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
10	BWR Vessel Internals (A.2.2.7)	XI.M9	Continue the existing BWR Vessel Internals AMP, including enhancements to: a) Add BWRVIP-19-A which provides guidelines for repair design criteria into the Vessel and Internals program and add to the Vessel and Internals Program – Reactor Vessel Internals Bases Document. b) Include implementation of BWRVIPs -26-A, -41-R4-A, -47-A, and -183-A as indicated in BWRVIP-315. c) A revision to BWRVIP-315-A, “Reactor Internals Aging Management Evaluation for Extended Operations” was published in April 2024 (ML24191A266). A proprietary and NP version was forwarded to NRC on 6/18/24 (ML24191A244). HNP has initiated a	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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			tracking item for implementing this new version of BWRVIP-315 as well as approved revisions to the above BWRVIP guidance documents into the program. d) Add BWRVIP-234 to the Vessel and Internals program and add to the Vessel and Internals Program – Reactor Vessel Internals Bases Document.	
11	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (A.2.2.8)	XI.M12	Implement the new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
12	Flow-Accelerated Corrosion (A.2.2.9)	XI.M17	Continue the existing Flow-Accelerated Corrosion AMP, including enhancements to: a) 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. b) Formalize a separate erosion susceptibility evaluation (ESE) that will include all components determined to be susceptible to wall loss due to erosion through OE and industry guidance. c) Revise or provide procedure(s) for measuring wall thickness due to erosion. Wall thickness should be trended to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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			d) 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 surveillance or pump starts/stops, then trending activities should consider the number or duration of these occurrences. e) Revise or provide procedure(s) to perform periodic wall thickness measurements of replacement components until the effectiveness of corrective actions have been confirmed. f) Revise or provide procedure(s) to provide guidance consistent with the erosion service life safety factor from EPRI 3002023786 for locations with known erosion mechanisms. Changes that recommend an increase in safety factor to 2.0 will be documented.	
13	Bolting Integrity (A.2.2.10)	XI.M18	Continue the existing Bolting Integrity AMP, including enhancements to: a) Create a procurement document to ensure that the maximum yield strength of replacement or newly- procured pressure-retaining bolting material will be limited to an actual yield strength less than 150 ksi. b) Clarify that MoS_2 and other lubricants containing sulfur will be prohibited from use on pressure-retaining closure bolting. c) Ensure that closure bolting where leakage is difficult to detect (e.g., piping systems that are submerged or that contain compressed 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	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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			will be 20 percent of the population (up to a maximum of 19 per Unit). d) Ensure non-ASME Section XI high-strength closure bolting (with actual yield strengths greater than or equal to 150 ksi), and bolting for which yield strength is unknown, will be monitored for surface and subsurface discontinuities indicative of cracking. e) Ensure that bolted joints in areas that are accessible during normal operation are visually inspected once per refueling cycle. f) Ensure that bolted joints not readily visible during plant operations and refueling outages will be visually inspected when they are made accessible and at such intervals that would provide reasonable assurance the components’ intended functions are maintained. g) Ensure that closure bolting greater than two inches 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 ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1. h) 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.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			i) Include the guidance for corrective action in response to joint leakage (i.e., sample expansion and additional inspections if inspection results do not meet acceptance criteria).	
14	Open-Cycle Cooling Water System (A.2.2.11)	XI.M20	Continue the existing Open-Cycle Cooling Water AMP, including enhancements to: a) Update the piping inspection procedures to monitor for internal cracking in copper alloys with greater than 15 percent zinc. b) Update the service water systems heat exchanger testing procedures to require the final heat exchanger testing frequency to be at least once every five years. c) 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. d) Clarify in 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. e) Ensure the service water program and heat exchanger inspection procedures prompt an evaluation of the heat transfer capability of the safety-related, raw water supplied heat exchangers when fouling is identified. f) Ensure service water program and inspection procedures include trending of wall thickness measurements at locations susceptible to ongoing degradation due to specific aging mechanisms (e.g., MIC). Ensure the monitoring frequency and number of inspection locations is adjusted based on the trending.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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			g) Update the service water program procedure and inspection and testing procedures to clarify that if fouling is identified, the overall effect is evaluated for flow blockage, loss of material, reduction in heat transfer, and chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC) or 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 service water 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 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. Regardless of which unit the condition is identified, the additional number of inspections will be performed on Unit 1 and Unit 2 where the same material, environment, and aging effect combination exists (each unit will perform a minimum of five additional inspections or 20 percent of each applicable material, environment, and aging effect combination, whichever is less).	
15	Closed Treated Water Systems (A.2.2.12)	XI.M21A	Continue the existing Closed Treated Water Systems AMP, including enhancements to: a) 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	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.:

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			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. b) Update implementing procedure(s) to include monitoring frequencies that are in accordance with the latest version of the EPRI Closed Cooling Water Chemistry Guideline for non-glycol systems. c) Update implementing procedure(s) or create new 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. d) Update implementing procedure(s) or create new procedure(s) to include acceptance criteria for the results of visual inspection of surfaces exposed to the closed treated water environment. Any	Unit 1: 02/06/2034 Unit 2: 12/13/2037

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			detectable loss of material, cracking, or fouling (of heat transfer surfaces) will be evaluated in the CAP. e) 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. Corrective actions will include additional inspections. The number of increased inspections will be determined in accordance with the CAP; however, 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 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. The additional inspections include inspections at all of the HNP units that have the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.	
16	Inspection of Overhead Heavy Load and Light Load	XI.M23	Continue the existing Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, including enhancements to:	No later than the last refueling outage prior to the SPEO, or

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
	(Related to Refueling) Handling Systems (A.2.2.13)		a) Update procedures to state the visual inspection frequencies required by the 1976 version of ASME B30.2. 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). b) Update procedures to specifically require visual inspectors to be VT qualified in accordance with plant-specific procedures and processes. c) Update procedures to state that repairs made to NUREG-0612 load handling systems are performed as specified in the 1976 version of ASME B30.2. d) Update 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 as required by ASME B30.2 or other applicable industry standard in the ASME B30 series. e) Update procedures to state that any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components is noted and corrective actions will be implemented in accordance with the CAP. f) Update procedures to state that the acceptance criteria for steel structures and connections guidelines from the Structural Monitoring Program for the maintenance shall be used.	no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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17	Compressed Air Monitoring (A.2.2.14)	XI.M24	Implement the new Compressed Air Monitoring AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
18	Fire Protection (A.2.2.15)	XI.M26	Continue the existing Fire Protection AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
19	Fire Water System (A.2.2.16)	XI.M27	Continue the existing Fire Water System AMP, including enhancements to: a) Specifically discuss inspection of the quality of the caulking or sealant at the tanks' foundation interface. b) HNP will provide technical justification that will demonstrate the water is not corrosive to the sprinklers based on past testing results so that sprinkler head testing and replacement requirements can be removed from the sprinkler head inspection procedure. c) Perform volumetric wall thickness inspections of the normally dry piping that cannot be drained or piping segments that allow water to collect. d) In each 5-year interval, beginning five years prior to the SPEO, either conduct a flow test or flush sufficient to detect potential flow	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the pre-SPEO tests and inspections during the 10 years prior to the SPEO for the fire water storage tanks. For other components with

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			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. e) Ensure a flow test will be conducted in the 5 year period prior to the SPEO at the hydraulically most remote hose connection of each building to verify the water supply. Where a flow test of the hydraulically most remote hose connection is not practical, engineering will be consulted for the appropriate location for the test. Subsequent tests at the most remote hose connection during the SPEO will be conducted every 5 years on a representative sample of 20 percent of the population (defined as components having the same material and environment combination) or a maximum of 25 per population at each unit. f) Perform volumetric inspections or low-frequency electromagnetic testing of all fire water storage tank walls if there are signs of degradation. g) Ensure when there are signs or age-related degradation detected in the vicinity of welds, the fire water storage tanks shall be vacuum-box tested at bottom seams in accordance with test procedures found in NFPA 22. h) Update fire water storage tank inspections to have the bottom surfaces inspected. Specifically, for each 10-year period starting 10 years before the SPEO, low-frequency electromagnetic testing or volumetric inspection of the tank bottom will be performed from the inside surface of the tanks. Any regions below nominal plate thickness (in excess of plate manufacturing tolerance) will have a follow-up ultrasonic thickness reading. If there are areas of significant loss of material that could impact the pressure boundary function, future ultrasonic thickness measurements and trending will be performed.	pre-SPEO inspections and tests, implement during the 5 years prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			i) For main drain tests, ensure 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. j) An internal inspection of piping and branch line conditions shall be conducted 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. 1. Update to permit alternative nondestructive examination methods that can ensure that flow blockage will not occur. 2. Include inspections to discuss tubercules or slime, if found, shall be tested for indications of microbiologically influenced corrosion (MIC). 3. State 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 NFPA 25 Section 14.3. 4. State that inspection of a cross main is not required where the system does not have a means of inspection. 5. 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 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.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			k) Conduct an obstruction investigation for system or yard main piping wherever any of the following conditions exist: 1. The discharge of obstructive material during routine water tests 2. Foreign materials in fire pumps, in dry pipe valves, or in check valves 3. Foreign material in water during drain tests or plugging of inspector's test connection(s) 4. Plugged sprinklers 5. Plugged piping in sprinkler systems dismantled during building alterations 6. Pinhole leaks 7. 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. If any of the above obstruction conditions are present, HNP will initiate a CR and will be investigated and resolved through the CAP. l) Clarify to include monitoring and trending of data to confirm that components will maintain their intended functions throughout the SPEO based on projected rate and extent of degradation if any degradation is identified. m) Clarify to measure wall thickness to compare the wall thickness to the minimum design if there is degradation identified. Wall thicknesses less than the minimum design will be entered into the CAP process for engineering evaluation.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			n) Demonstrate that no loose fouling products exist in the systems that could cause flow blockage in the sprinklers or deluge nozzles. o) When all the flow tests at the most hydraulically remote hose connections of each building conducted no earlier than 5 years prior to the subsequent period of extended operation meet the design pressure at the required flow acceptance criteria, subsequent tests of the most remote hose connections may be conducted on a representative sample of 20 percent of the population (defined as components having the same material and environment combination) or a maximum of 25 per population at each unit.	
20	Outdoor and Large Atmospheric Metallic Storage Tanks (A.2.2.17)	XI.M29	Continue the existing Outdoor and Large Atmospheric Metallic Storage Tanks AMP, including enhancements to: a) Update the implementation procedure title to reflect that this AMP requires more than visual examinations on the CSTs. This procedure references other examination types used in CST examinations that satisfy the requirements of the current LR. b) Update section 2.0 of the AMP implementation procedure to reflect the applicability and frequency of the inspections outlined in the AMP basis document. c) Update the AMP implementation procedure examination checklist to include inspection areas exposed to all tank environments (i.e., ensure test sample group includes tank wall areas exposed to air/condensation and water). d) Perform an internal volumetric inspection of the tank bottom for loss of material and cracking. The frequency is “each 10-year period starting 10 years before the SPEO."	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the pre-SPEO inspections no earlier than 10 years prior to the SPEO.

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			e) Enhance the AMP implementation procedure to include the following: when degraded conditions are identified, acceptability of the condition is projected to the next scheduled inspection or in the case of one-time inspections, follow-up inspections are scheduled. f) Enhance the AMP implementation procedure to include the following: results are evaluated against acceptance criteria to confirm or adjust timing of subsequent inspections, or in the case of one-time inspections, schedule follow-up inspections. g) Enhance the examination section of the AMP implementation procedure to include the coated areas for examination and to add a specific examination task to inspect the condition of coatings, sealants, and caulking along with physical manipulation of sealants and caulking. h) Enhance the sample set expansion requirements of the AMP implementation procedure to state the number of increased inspections is determined in accordance with the site's CAP. However, for other sampling-based inspections (e.g., 20 percent, 25 locations) the smaller of five additional inspections or 20 percent of the inspection population will be conducted. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause will be conducted to determine the further extent of inspection.	
21	Fuel Oil Chemistry (A.2.2.18)	XI.M30	Continue the existing Fuel Oil Chemistry AMP, including enhancements to: a) Create a new implementing procedure for the fire pump diesel storage tanks cleaning and inspections, which has the following: 1. Steps for cleaning and volumetric examinations for signs of loss of material every 10 years. If there are signs of loss of	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			material of tank wall thickness, include steps for repairs or additional evaluations. 2. Identified degradation is projected until the next scheduled inspection, where practical. 3. Results are evaluated against acceptance criteria to confirm that the components will maintain the intended functions based on the projected rate of degradation throughout the SPEO. 4. Thickness measurements are evaluated against the design thickness and corrosion allowance. Any degradation identified during volumetric examinations is reported and evaluated using the CAP. b) Ensure that the following inspections and examinations are included in the FOST inspections: 1. Steps for repairs or volumetric inspections of the tank wall thickness if there are any signs of corrosion during the visual inspections every 10 years. 2. Identified degradation is projected until the next scheduled inspection, where practical. 3. Results are evaluated against the acceptance criteria to confirm that the components will maintain the intended functions based on the projected rate of degradation throughout the SPEO. 4. Thickness measurements are evaluated against the design thickness and corrosion allowance. Any degradation identified during volumetric examinations is reported and evaluated using the CAP.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			c) Ensure that the following inspections and examinations are included in the diesel generator day tank inspections: 1. Steps for cleaning and visual inspections for signs of corrosion of the diesel generator day tanks every 10 years. Include steps for repairs or additional volumetric examinations to verify the tank wall thickness if there are signs of corrosion. 2. Identified degradation is projected until the next scheduled inspection, where practical. 3. Results are evaluated against the acceptance criteria to confirm that the components will maintain the intended functions based on the projected rate of degradation throughout the SPEO. 4. Any visual degradation of the diesel generator day tanks is reported and evaluated by generating a CR. 5. Thickness measurements are evaluated against the design thickness and corrosion allowance. Any degradation during the visual inspections or volumetric inspections is reported and evaluated using the CAP. d) Ensure that the following is updated in the fuel oil chemistry inspections: 1. Testing, monitoring, and trending frequency for biological activity will be updated to at least quarterly.	
22	Reactor Vessel Material Surveillance (A.2.2.19)	XI.M31	Continue the existing Reactor Vessel Material Surveillance AMP, including enhancement to: a) Implement BWRVIP-321 Revision 1-A to maintain compliance with 10 CFR 50, Appendix H. during the SPEO.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.:

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23	One-Time Inspection (A.2.2.20)	XI.M32	Implement the new One-Time Inspection AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 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	Implement the new Selective Leaching AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO.

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25	ASME Code Class 1 Small-Bore Piping (A.2.2.22)	XI.M35	Implement the new ASME Code Class 1 Small-Bore Piping AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Start the one-time and 10-year interval inspections no earlier than 6 years prior to the SPEO.
26	External Surfaces Monitoring of Mechanical Components (A.2.2.23)	XI.M36	Implement the new External Surfaces Monitoring of Mechanical Components AMP.	No later than the last refueling outage prior to the SPEO or no later than 6 months prior to the SPEO, i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
27	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (A.2.2.24)	XI.M38	Implement the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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28	Lubricating Oil Analysis (A.2.2.25)	XI.M39	Continue the existing Lubricating Oil Analysis AMP, including enhancement to: a) Update the lubricating oil analysis procedures to clarify that phase-separated water in any amount is not acceptable.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
29	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (A.2.2.26)	XI.M40	Continue the existing Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP, including enhancements to: a) Update the surveillance sample removal and installation procedure to assure EPRI good practices are being used to maintain acceptable chemistry parameters and the corresponding coupon inspection PM tasks specifically document any aluminum oxide layer degradation on the coupon.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
30	Buried and Underground Piping and Tanks (A.2.2.27)	XI.M41	Continue the existing Buried and Underground Piping and Tanks AMP, including enhancements to: a) Update the Excavation & Earthwork Quality Control procedure to state that new and replacement backfill shall meet the requirements of NACE SP-0169-2007 Section 5.2.3 or NACE RP-0285-2002 Section 3.6. Backfill that is located within 6 inches of the component that meets ASTM D 448-08 size number 67 (size number 10 for polymeric materials) is considered to meet the objectives of NACE SP0169-1 2007 and NACE RP0285-2002. For stainless steel, backfill limits apply only if the component is coated. The use of controlled low-strength materials (flowable backfill) is also acceptable to meet the objectives of NACE SP0169-2007.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the 10-year period inspections no earlier than 10 years prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			b) Update the BUPT implementing procedure to perform soil testing during excavations for inspections. Additionally, include a requirement to perform an evaluation at least every five years during the SPEO to ensure the soil samples taken during that period are representative of the vicinity in which in-scope components are buried. c) Install cathodic protection on the diesel fuel oil storage tanks prior to the SPEO. The cathodic protection system installed on the diesel fuel oil storage tanks will be in accordance with NACE SP0169-2007 or NACE RP0285-2002. d) Update procedures and/or specifications to require that newly installed, buried stainless steel piping is coated in accordance with Table 1 of National Association of Corrosion Engineers (NACE) SP0169-2007 or Section 3.4 of NACE RP0285-2002. e) Update the BUPT implementing procedure to monitor for crevice corrosion and MIC for copper alloy, steel (including ductile and gray cast iron), and stainless steel components. f) Update the BUPT implementing procedure to clarify that inspections for cracking due to SCC for stainless steel and steel (in a carbonate-bicarbonate environment) utilize 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 period; 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. g) Update fuel oil storage tank inspection and cleaning tasks to align with a 10-year frequency.	

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			h) Update the BUPT implementing procedure to specify that visual inspections are supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed. i) Update the BUPT implementing procedure to include the following: Where practical, identified degradation (e.g., coating condition) is projected until the next scheduled inspection occurs. 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. j) Update the BUPT implementing procedure to include the following acceptance criteria: 1. For coated piping or tanks, there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as being insignificant by (1) an individual who has a NACE Coating Inspector Program Level 2 or 3 inspector qualification; (2) an individual who has completed the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course; or (3) 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." 2. The measured wall thickness projected to the end of the SPEO meets minimum wall thickness requirements. 3. Indications of cracking in metallic pipe are managed in accordance with the "corrective actions" program element.	

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			4. 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). 5. Cracks in cementitious backfill that could admit groundwater to the surface of the component are not acceptable. k) Update the BUPT implementing procedure to include the following corrective actions: 1. Where damage to the coating has been evaluated as being 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. 2. If coated or uncoated metallic piping or tanks show evidence of corrosion, the remaining wall thickness in the affected area is determined to ensure that the minimum wall thickness is maintained. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the SPEO meets the minimum wall thickness requirements, the recommendations for expansion of sample size below do not apply. 3. When the coatings, backfill, or condition of exposed piping does not meet the acceptance criteria, the degraded condition is repaired or the affected component is replaced. In addition, 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, an expansion of sample size is conducted. The number of inspections within the affected	

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			piping categories is 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. 4. 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 period during which the original inspection was conducted or, if identified during the latter half of the current 10-year period, within 4 years after the end of the 10-year period. These additional inspections conducted during the 4 years following the end of an inspection period cannot also be credited toward the number of inspections for the following 10-year period. The number of inspections may be limited by the extent of piping or tanks subject to the observed degradation mechanism. 5. The expansion of sample inspections may be halted in a piping system or portion of system that will be replaced within the 10-year period during which the inspections were conducted or, if identified during the latter half of the current 10-year period, within 4 years after the end of the 10-year period. 6. Indications of cracking are evaluated in accordance with applicable codes and plant-specific design criteria. l) Update the Underground Piping and Tanks Asset Management Plan to include:	

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			1. The required inspections for SLR. 2. A requirement that newly installed, buried stainless steel piping is coated in accordance with Table 1 of National Association of Corrosion Engineers (NACE) SP0169-2007 or Section 3.4 of NACE RP0285-2002.	
31	Internal Coatings/Linings for In-scope Piping, Piping Components, Heat Exchangers, and Tanks (A.2.2.28)	XI.M42	Implement the new Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and perform pre-SPEO baseline inspections no earlier than 10 years prior to the SPEO.
32	ASME Section XI Subsection IWE (A.2.2.29)	XI.S1	Continue the existing ASME Section XI, Subsection IWE AMP, including enhancements to: a) Specify the preventive actions for storage, lubricants, and SCC 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) Monitor accessible portions of high-temperature (temperatures above 140°F) drywell piping penetrations that are not pressurized	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			during local leak rate testing and have no CLB fatigue analysis to detect cracking. c) Perform supplemental one-time surface or enhanced visual examinations comprising a representative sample (five per unit) of the stainless steel penetrations or DMWs associated with high-temperature (temperatures above 140°F) stainless steel piping systems in frequent use to confirm the absence of SCC aging effects. d) 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 percent of nominal plate thickness) that is determined to originate from the inaccessible side. Guidance provided in EPRI TR–107514 will be considered when establishing a sampling plan. This sampling is conducted to demonstrate, with 95 percent confidence, that 95 percent of the accessible portion of the metal shell is not experiencing greater than 10 percent wall loss. e) 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 incrementing sample size during the current outage by one additional penetration at a time from the uninspected population of stainless steel penetrations or DMWs associated with high-temperature (greater than 140°F) stainless steel piping systems in frequent use until cracking is no longer detected. Periodic inspection of subject penetrations with DMWs for cracking will be	

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			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	Continue the existing ASME Section XI, Subsection IWF AMP, including enhancements to: a) 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) Specify the preventive actions for storage, lubricants, and SCC 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. c) Perform and document a one-time supplemental inspection of an additional 5 percent of the sample size specified in Table IWF-2500-1 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 (i.e., based on time in service, aggressive environment, etc.). The one-time inspection will occur within five years prior to entering the SPEO. d) Specify that, for component supports with high-strength bolting greater than one-inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. 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	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement and start the pre-SPEO one-time supplemental support inspections no earlier than 5 years prior to entering the SPEO.

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			population of ASME Class 1, 2, 3, and MC high-strength structural bolting greater than one-inch nominal diameter within the boundaries of IWF-1300 and establish a sample to be 20 percent of the population (for a material / environment combination) up to a maximum of 19 bolts. e) If a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired. f) Specify that the following conditions are also unacceptable: 1. Loss of material due to corrosion or wear; 2. Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support; 3. Cracked or sheared bolts, including high-strength bolts, and anchors.	
34	10 CFR Part 50, Appendix J (A.2.2.31)	XI.S4	Continue the existing 10 CFR Part 50, Appendix J AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
35	Masonry Walls (A.2.2.32)	XI.S5	Continue the existing Masonry Walls AMP, including enhancements to: a) Update the implementing procedure to require inspections for masonry walls to be performed every five years	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
36	Structures Monitoring (A.2.2.33)	XI.S6	Continue the existing Structures Monitoring AMP, including enhancements to: a) Specify that the following component types are contained in the scope: airlocks, ballistic shields, bird screens, louvers, stairs, ladders, handrails, platforms, sliding surfaces, new fuel storage racks, pit boxes, reactor shield wall, refueling water seal assembly, and the RPV pedestal. b) Specify the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connection publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used for structural bolting consisting of American Society for Testing and Materials (ASTM) A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts. c) Clarify that in addition to MoS_2 lubricants, “other lubricants containing sulfur” will not be used on high- strength bolting. d) Clarify that in addition to watertight, missile and pressure doors, “doors for shelter and protection” are inspected. e) 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.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and perform pre-SPEO baseline tests and inspections prior to the SPEO.

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			Considerations may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. f) Include surface staining in the list of alkali-silica reaction (ASR) indications. g) Inspect and monitor the loss of material due to pitting or crevice corrosion and cracking in stainless steel and aluminum components. h) Inspect and monitor the loss of mechanical function for sliding surfaces. i) Inspect and monitor below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil which will include the performance of a baseline visual inspection prior to the SPEO at a minimum of one location which has experienced aggressive groundwater. The baseline inspection results will be used to conduct a baseline evaluation that will determine the additional actions (if any) that are warranted. j) Perform a baseline evaluation prior to the SPEO of the baseline inspection results for below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. The evaluation will consider the baseline inspection results to determine the additional actions (if any) that are warranted. Additional actions may include: enhanced inspection techniques and/or frequency, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. The baseline inspection and evaluation results will set the subsequent inspection requirements and inspection intervals (not to exceed 5 years) for the SPEO.	

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
			k) Perform periodic evaluation updates of below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil (not to exceed 5 years). Updates will be based on OE, periodic inspections, and will consider the opportunistic or focused inspection results during the interval. The periodic evaluation results will update subsequent inspection requirements and inspection intervals (not to exceed 5 years) for the SPEO as required. l) Inspections for all structures within the scope of the Structures Monitoring AMP to be performed every five years or the next scheduled refueling outages following the five year interval in normally inaccessible areas. m) Include qualification requirements specified in ACI 349.3R-02 for inspection team members and examiners. n) Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation of such inaccessible areas. o) Include acceptance criteria for the following components and associated aging effects: 1. Polystyrene blowout panels (loss of material and cracking). 2. Stainless steel and aluminum components (loss of material - pitting or crevice corrosion and cracking). 3. Sliding surfaces (loss of mechanical function).	
37	Inspection of Water-Control Structures Associated with	XI.S7	Continue the existing Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, including enhancements to:	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO i.e.:

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
	Nuclear Power Plants (A.2.2.34)		a) Update the implementing procedure to include stop logs in the scope of the Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP. b) Specify the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connection publication, "Specification for Structural Joints Using High-Strength Bolts," will be used for structural bolting consisting of American Society for Testing and Materials (ASTM) A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts. c) Update the implementing procedure to clarify that in addition to MoS_2 lubricants, "other lubricants containing sulfur" will not be used on high-strength bolting. d) Update the implementing procedure to require inspections for Water-Controlled Structures to be performed every five years. e) Update 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. f) Update the implementing procedure to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation of such inaccessible areas.	Unit 1: 02/06/2034 Unit 2: 12/13/2037
38	Protective Coating Monitoring and	XI.S8	Continue the existing Protective Coating Monitoring and Maintenance AMP, including enhancements to:	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
	Maintenance (A.2.2.35)		a) Update the implementing procedure 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. b) Update the implementing procedure to reference C4 of RG 1.54 Rev. 3 for maintenance of Service Level I Coatings.	the SPEO i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
39	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (A.2.2.36)	XI.E1	Continue the existing Electrical Insulation for Electrical Cables and Connections Not subject to 10 CFR 50.49 Environmental Qualification Requirement AMP, including an enhancement to: a) Update the implementing procedure to require visual inspections for accessible electrical cables and connections subjected to an ALE be performed every 10 years.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the 10-year interval inspections prior to the SPEO.
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	Continue the existing Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP, including enhancements 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, which are not subject to cable circuit testing. Perform the first periodic review for SLR prior to the SPEO and at least every 10 years thereafter.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the 10-year interval inspections prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	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	Continue the existing Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, including enhancements to: a) Update definitions of significant moisture as exposure to moisture that lasts more than 3 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. b) Include submarine or other cables designed for continuous wetting or submergence as a one-time inspection and test with additional periodic tests and inspections determined by the one-time test/inspection results as well as industry and plant-specific OE. c) Include inspection of pull boxes equipped with remote water level monitoring and alarms that result in consistent and subsequent pumpout of accumulated water prior to the wetting or submergence of cables at least once every 5 years. d) Inspect pull boxes for water accumulation after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. e) Ensure the reliability, self-monitoring features, and operation of continuous remote water level and alarm capabilities of such devices, if installed and credited for 5-year inspection intervals, are demonstrated routinely depending on the attributes of the specific equipment used. f) Test medium-voltage power cables within the scope of this program at least once every 6 years.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and complete the one-time 5 year and 6 year interval inspections no later than 6 months prior to the SPEO.

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	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	Implement the new Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the annual inspections 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	Implement the new Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement the AMP and start the 6-year interval inspections prior to the SPEO.
44	Fuse Holders (A.2.2.41)	XI.E5	Implement the new Fuse Holders AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.:

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List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
				Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement AMP and start the inspections prior to the SPEO.
45	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (A.2.2.42)	XI.E6	Implement the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
46	High-Voltage Insulators (A.2.2.43)	XI.E7	Implement the new High-Voltage Insulators AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO. i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037 Implement AMP and start the inspections prior to the SPEO.
47	RHR Heat Exchanger Augmented	N/A	Continue the existing RHR Heat Exchanger Augmented Inspection AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO i.e.:

Table A-3
List of SLR Implementation Actions and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Action Description	Implementation Schedule
	Inspection Program (A.2.3.1)			Unit 1: 02/06/2034 Unit 2: 12/13/2037
48	Torus Submerged Components Inspection Program (A.2.3.2)	N/A	Continue the existing Torus Submerged Components Inspection AMP.	No later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO i.e.: Unit 1: 02/06/2034 Unit 2: 12/13/2037
49	Quality Assurance Program (A.1.3)	Appendix A	The Quality Assurance Program is an existing program that is credited.	Ongoing
50	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

HATCH NUCLEAR PLANT

SUBSEQUENT LICENSE RENEWAL APPLICATION

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B.1 INTRODUCTION

B.1.1 Overview

The subsequent license renewal (SLR) aging management program (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 subsequent license renewal application (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 (SC) to perform its intended function.

More than one type of AMP may be implemented for systems, structures, and components (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 have 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 plant programs as appropriate. However, some existing programs aligned with multiple NUREG-2191 AMPs, and some NUREG-2191 AMPs aligned with multiple programs. Therefore, the existing AMPs to be continued for SLR will be renamed as applicable to align with the NUREG-2191 AMP names. In some instances, a new AMP is created where existing aging management activities do not entirely align with NUREG-2191 recommendations. All existing 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.

Current programs have been demonstrated to adequately manage the identified aging effects during the original Period of Extended Operation (PEO). If an existing program does not adequately manage an identified aging effect, the finding is entered into the corrective action program (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 for the purposes of SLR:

- Neutron Fluence Monitoring AMP (Section B.2.2.3)
- Reactor Head Closure Stud Bolting AMP (Section B.2.3.3)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP (Section B.2.3.8)

- Compressed Air Monitoring AMP (Section B.2.3.14)
- One-Time Inspection AMP (Section B.2.3.20)
- Selective Leaching AMP (Section B.2.3.21)
- ASME Code Class 1 Small-Bore Piping AMP (Section B.2.3.22)
- External Surfaces Monitoring of Mechanical Components AMP (Section B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (Section B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.28)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.39)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.40)
- Fuse Holders AMP (Section B.2.3.41)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.42)
- High Voltage Insulators AMP (Section B.2.3.43)

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:

- Water Chemistry AMP (Section B.2.3.2)
- Reactor Head Closure Stud Bolting AMP (Section B.2.3.3)
- BWR Vessel ID Attachment Welds AMP (Section B.2.3.4)
- Fire Water System AMP (Section B.2.3.16)
- Buried and Underground Piping and Tanks AMP (Section B.2.3.27)
- Structures Monitoring AMP (Section B.2.3.33)

B.1.2 Method of Discussion

For those 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 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 AMP for SLR is effective or will be effective when implemented if new or enhanced.

B.1.3 Quality Assurance Program and Administrative Controls

The QA program 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 QA program is consistent with NUREG-2191 Appendix A. The 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 CAP is applied regardless of the safety classification of the SSC or commodity group. The CAP requires the initiation of a Condition Report (CR) 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 a CR 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 CAP specifies that for equipment conditions a CR 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 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), will be used to meet Element 7, Corrective Actions.

<u>Confirmation Process</u>

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 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 CAP provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The 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 CR. 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 AMPs for SLR: 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 QATR, will be used to meet Element 8, Confirmation Process.

The confirmation process is part of the CAP 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 CAP. The CAP constitutes the confirmation process for AMPs 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 Subsequent Period of Extended Operation (SPEO).

The following statement is applicable to all the AMPs for SLR: 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) SNC-1, will be used to meet the required Administrative Controls.

B.1.4 Operating Experience

Internal operating experience (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 OE program. The OE program meets the recommendations of NUREG-0737, *Clarification of TMI Action Plan*

Requirements, Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff."

OE is used to enhance existing programs, prevent repeat events, and prevent events that have occurred at other plants. Through INPO, as well as other sources, Hatch Nuclear Plant (HNP) receives external OE routinely. The OE process reviews OE from external and internal sources. HNP personnel screen, evaluate, and act on OE documents and information to prevent or mitigate the consequences of similar events. External OE includes INPO documents, Nuclear Regulatory Commission (NRC) documents (e.g., Information Notices (IN), Regulatory Information Summaries (RISs), Generic Letters (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), The American Concrete Institute (ACI), API, NACE, International Organization for Standardization); (b) Electric Power Research Institute (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 HNP 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. HNP meets the guidance of Nuclear Energy Institute (NEI) 14-13, *Use of Industry Operating Experience for Age-related Degradation and Aging Management Programs* regarding the use of industry OE for AMPs.

The OE program meets the guidance of NEI 14-12, *Aging Management Program Effectiveness*. The OE program interfaces with and relies on active participation in the INPO OE program, as endorsed by the NRC. HNP 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 a CR 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. The latest effectiveness review was performed in the fourth quarter of 2022.

Each AMP summary in this appendix contains a discussion of OE relevant to the AMP taken from a time period 10 years prior to the 9/30/2024 cutoff date. 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, 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. The OE program is consistent with NUREG-2191 Appendix B.

In addition, for multi-unit sites where sample size is not based on their percentage of the population and the inspections are conducted periodically (not one-time inspections), reduced inspections for several AMPs are acceptable. In order to conduct the reduced number of inspections, operating conditions at each unit must be demonstrated to be similar enough to provide representative inspection results. Based on the following aspects, the HNP units are similar enough such that inspections at one unit are representative of the other unit and reduced inspection quantities can be credited:

- HNP Units 1 and 2 were approved for power uprate from 2436 MWt to 2558 MWt on August 31, 1995.
- HNP Units 1 and 2 were approved for extended power uprate (EPU) from 2558 MWt to 2763 MWt on October 22, 1998
- HNP Units 1 and 2 were approved for thermal power optimization (TPO) power uprate from 2763 MWt to 2804 MWt on September 23, 2003
- OE has not indicated a trend of out-of-spec water chemistry conditions that would differentiate one unit from the other. Condition Report keyword searches “water chem”, “MIC”, “micro”, “ammoni”, “dezinc”, and “de-zinc” yield no plant OE that indicates long term or repeated out-of-spec water chemistry conditions.
- The Altamaha River is the source for the cooling water systems, such as the residual heat removal service water (RHRSW) and plant service water (PSW) systems. There are no operational differences between the units’ cooling water systems. Condition Report keyword searches for “MIC” and “microb” cross referenced with “raw” and “ICW” yielded no trends of increased MIC degradation between Units 1 and 2 for raw water systems.
- Per HNP Technical Specifications, the diesel fuel oil for the respective diesel generators is tested at the same frequency.
- Water systems common to both units have the same chemistry requirements and operate at similar temperatures.

B.1.5 Aging Management Programs

Table B-1 lists the 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). Existing AMPs are based on either an existing LR AMP or existing plant program. Additionally, Table B-2 lists the 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 HNP Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
X.E1	B.2.2.1	Environmental Qualification of Electric Equipment	Existing
X.M1	B.2.2.2	Fatigue Monitoring	Existing
X.M2	B.2.2.3	Neutron Fluence Monitoring	New
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.E5	B.2.3.41	Fuse Holders	New
XI.E6	B.2.3.42	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New

Table B-1
List of HNP Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.E7	B.2.3.43	High-Voltage Insulators	New
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	New
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	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	New
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	Existing
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	New
XI.M35	B.2.3.22	ASME Code Class 1 Small-Bore Piping	New
XI.M36	B.2.3.23	External Surfaces Monitoring of Mechanical Components	New
XI.M38	B.2.3.24	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	New

Table B-1
List of HNP Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
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
N/A (Plant-specific)	B.2.4.1	RHR Heat Exchanger Augmented Inspection	Existing
N/A (Plant-specific)	B.2.4.2	Torus Submerged Components Inspection	Existing

Table B-2
Aging Management Programs

HNP 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
Buried and Underground Piping and Tanks	B.2.3.27	XI.M41
BWR Penetrations	B.2.3.6	XI.M8
BWR Stress Corrosion Cracking	B.2.3.5	XI.M7
BWR Vessel ID Attachment Welds	B.2.3.4	XI.M4
BWR Vessel Internals	B.2.3.7	XI.M9
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.2.2.1	X.E1
External Surfaces Monitoring of Mechanical Components	B.2.3.23	XI.M36

Table B-2
Aging Management Programs

HNP Aging Management Program	Section	NUREG-2191 Section
Fatigue Monitoring	B.2.2.2	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
Fuse Holders	B.2.3.41	XI.E5
High-Voltage Insulators	B.2.3.43	XI.E7
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.24	XI.M38
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
Monitoring of Neutron-Absorbing Materials Other Than Boraflex	B.2.3.26	XI.M40
Neutron Fluence Monitoring	B.2.2.3	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 Head Closure Stud Bolting	B.2.3.3	XI.M3
Reactor Vessel Material Surveillance	B.2.3.19	XI.M31
RHR Heat Exchanger Augmented Inspection	B.2.4.1	N/A (Plant-specific)
Selective Leaching	B.2.3.21	XI.M33
Structures Monitoring	B.2.3.33	XI.S6
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	B.2.3.8	XI.M12

Table B-2
Aging Management Programs

HNP Aging Management Program	Section	NUREG-2191 Section
Torus Submerged Components Inspection	B.2.4.2	N/A (Plant-specific)
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 AMPs is shown in Table B-3. Links to the sections describing the NUREG-2191 programs are provided. Table B-4 presents the AMPs, corresponding NUREG-2191 AMP name, whether or not the AMP has enhancements to align with NUREG-2191 or takes exception to NUREG-2191 recommendations.

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	HNP Aging Management Program
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment (B.2.2.1)
X.M1	Fatigue Monitoring	Fatigue Monitoring (B.2.2.2)
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring (B.2.2.3)
X.S1	Concrete Containment Unbonded Tendon Prestress	Not Applicable (HNP does not have a prestressed concrete containment.)
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)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	HNP Aging Management Program
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	Not Applicable (HNP does not have any components within the XI.E4 AMP scope)
XI.E5	Fuse Holders	Fuse Holders (B.2.3.41)
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	High-Voltage Insulators (B.2.3.43)
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 (HNP 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 (HNP is not a PWR)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	HNP Aging Management Program
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.3.8)
XI.M16A	PWR Vessel Internals	Not Applicable (HNP 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 (HNP is not a PWR)
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 (HNP 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 (HNP 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)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	HNP Aging Management Program
XI.M37	Flux Thimble Tube Inspection	Not Applicable (HNP 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)
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 (HNP 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)
Plant-Specific Program	N/A	RHR Heat Exchanger Augmented Inspection (B.2.4.1)
Plant-Specific Program	N/A	Torus Submerged Components Inspection (B.2.4.2)

Table B-4
HNP Aging Management Program Consistency with NUREG-2191

HNP Aging Management Program	Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements?	Exceptions?
Environmental Qualification of Electric Equipment	B.2.2.1	X.E1	Yes	No
Fatigue Monitoring	B.2.2.2	X.M1	Yes	No
Neutron Fluence Monitoring	B.2.2.3	X.M2	No (New)	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
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
Fuse Holders	B.2.3.41	XI.E5	No (New)	No
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.42	XI.E6	No (New)	No

Table B-4
HNP Aging Management Program Consistency with NUREG-2191

HNP Aging Management Program	Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements?	Exceptions?
High-Voltage Insulators	B.2.3.43	XI.E7	No (New)	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	No (New)	Yes
BWR Vessel ID Attachment Welds	B.2.3.4	XI.M4	No	Yes
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	No
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel	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	No (New)	No
Fire Protection	B.2.3.15	XI.M26	No	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	Yes	No
Fuel Oil Chemistry	B.2.3.18	XI.M30	Yes	No

Table B-4
HNP Aging Management Program Consistency with NUREG-2191

HNP Aging Management Program	Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements?	Exceptions?
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	No (New)	No
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	No (New)	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	Yes	No
Buried and Underground Piping and Tanks	B.2.3.27	XI.M41	Yes	Yes
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	No
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	Yes
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

Table B-4
HNP Aging Management Program Consistency with NUREG-2191

HNP Aging Management Program	Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements?	Exceptions?
RHR Heat Exchanger Augmented Inspection	B.2.4.1	N/A (Plant-specific)	No	No
Torus Submerged Components Inspection	B.2.4.2	N/A (Plant-specific)	No	No

B.2.2 NUREG-2191 Chapter X Aging Management Programs

B.2.2.1 Environmental Qualification of Electric Equipment

Program Description

The Environmental Qualification of Electric Equipment 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 environmental qualification (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 EQ of electrical equipment important to safety that could be exposed to harsh environment accident conditions as required by 10 CFR 50.49 and regulatory guide (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 break (HELB), or 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 HNP 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 master list (EQML) to ensure the equipment remains qualified. The Environmental Qualification 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 adverse localized environment (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 HNP EQ documentation packages are considered time-limited aging analyses (TLAAs) per 10 CFR 54.21(c)(1).

NUREG-2191 Consistency

The Environmental Qualification of Electrical Equipment AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section X.E1, "Environmental Qualification of Electrical Equipment."

Exceptions to NUREG-2191

None.

Enhancements

The 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	Enhancement
3 - Parameters Monitored/Inspected	The existing program will be enhanced to include monitoring or inspection of certain environmental conditions, including ALEs, or equipment parameters to verify that the equipment is within the bounds of its qualification basis, or as a means of modifying the qualified life.
4 - Detection of Aging Effects	Visual inspection of accessible, passive EQ equipment will be performed at least once every 10 years. The purpose of the visual inspection is to identify ALEs that may affect qualified life. Potential ALEs are evaluated through the CAP. The first periodic visual inspection is to be performed prior to the SPEO.
6 - Acceptance Criteria	Visual inspections, as part of other enhancements to this program, will document that accessible passive EQ equipment is free from unacceptable surface abnormalities that may indicate age degradation.
7 - Corrective Actions	Procedures will be enhanced to 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

Industry Operating Experience

HNP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

EQ programs include consideration of OE to modify qualification bases and conclusions, including qualified life such that the impact on the EQ program is evaluated and any necessary actions or modifications to the program are performed. Compliance with 10 CFR 50.49 provides reasonable assurance that EQ equipment can perform their intended functions during accident conditions after experiencing the effects of operational aging.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In September 2015, the EQ central files and Lists of Applicable Components were enhanced to provide clarification regarding Motor Control Centers (MCC) subcomponents qualified under the Division of Operating Reactors guidelines. Environmental Qualification Report Evaluations (EQREs) for MCCs were enhanced to confirm that EQ qualification under the Division of Operating Reactors (DOR) guidelines is allowed to continue in the PEO.
- In March 2017, a dent was discovered in the casing of an installed environmentally qualified valve by engineering. The component was determined to be fully qualified, but was conservatively replaced at the next opportunity.
- In August 2019, a potential enhancement to clarify wording in the Final Safety Analysis Report (FSAR) as it relates to methodologies utilized to calculate radiation doses was proposed. However, it was determined that the FSAR wording was adequate as written.
- In April 2020, an inspection of the Unit 2 condenser bay revealed degraded flex conduit on eight conduit runs where the conduit crossed a structural expansion joint. The conduits carry various instrumentation cables. The degradation was caused by steam leaks. Cable testing was performed and the conduit damage was repaired.
- In July 2021, it was discovered that temporary instrumentation measurement uncertainty was not accounted for when establishing qualified life of certain components. The condition was reviewed by engineering and determined to be insignificant to the calculation of the qualified life of the components.
- In February 2022, during EQ drywell cable inspections, a flexible conduit was found broken at the connection to the pull box for a relief valve, exposing the cable inside to the environment. The flex connector was repaired.
- In February 2022, during EQ drywell cable inspections, a cable was discovered with split insulation due to a sharp bend radius inside of a pull box. The cable was repaired.
- In February 2022, during EQ drywell cable inspections, a lug on a bare copper ground wire for a valve was found degraded. The ground wire was relugged and reattached.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Environmental Qualification of Electrical Equipment 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 periodically evaluated.

Conclusion

The Environmental Qualification of Electrical Equipment 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 current licensing basis (CLB) during the SPEO.

B.2.2.2 Fatigue Monitoring

Program Description

The Fatigue Monitoring AMP is an existing monitoring program that manages fatigue damage of the reactor pressure vessel (RPV) components, the torus, the reactor coolant pressure boundary Class 1 piping components and HELB 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 cumulative usage factor (CUF) and environmentally assisted fatigue (CUF_{en}) for each analyzed component does not exceed the applicable limit through the SPEO. The program monitors and tracks the number and severity of thermal and pressure transients as specified in FSAR Sections 4.2.5, 5.4.6.4 and 18.2.12. FSAR section 4.2 is referenced in technical specification 5.5.5, Component Cyclic or Transient Limit.

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 American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements for specific mechanical components; and (b) fatigue analysis calculations for assessing environmentally assisted fatigue (EAF). The Fatigue Monitoring AMP utilizes FatiguePro™, which is a computerized data acquisition, recording, and tracking software program, to determine the overall cumulative number of transients that have occurred and determine the CUF values resulting from the combination of transient occurrences. The FatiguePro™ software performs “cycle-based” and "stress-based" fatigue monitoring.

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 Section 4.3 provides details of the evaluation of fatigue for components that have a calculated CUF. All 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 HNP to ensure that all potential limiting component locations are captured, all the reactor coolant pressure boundary components with existing ASME Code fatigue analyses, including those HNP specific NUREG/CR-6260 locations, have been evaluated for EAF. SLRA Section 4.3.7 provides details of the evaluation for EAF for the SPEO. The effects of fatigue on the intended functions of the ASME Code, Section III components, and American National Standards Institute (ANSI) B31.1 piping components listed in Table 4.3.7-1 and Table 4.3.7-2 will be managed by this AMP through the use of FatiguePro™ and taking required actions prior to exceeding design limits that would invalidate their conclusions.

The cumulative CUF and CUF_{en} values for the components monitored are compared to appropriate allowable limits. 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, inspection, repair or replacement can be used to demonstrate that the fatigue design limit will not be exceeded during the SPEO.

NUREG-2191 Consistency

The 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 Fatigue Monitoring AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
3 - Parameters Monitored/Inspected	Update plant procedures to provide procedural direction to require periodic validation of chemistry parameters that are used as inputs to determine environmental correction factors (F_{en}).
3 - Parameters Monitored/Inspected	Update the Fatigue Monitoring AMP governing 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.
5 - Monitoring & Trending	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.

7 - Corrective Actions	The procedures governing the Fatigue Monitoring AMP will be enhanced to specify that for CUF_{en} analyses, any scope expansion will include consideration of other locations with the highest expected CUF_{en} values.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. An example of this is the following:

- 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.

  The methodology described in NUREG/CR-6909 was utilized in calculating the HNP F_{en} values for the SPEO.

- RIS 2008-30 was issued to address a concern regarding the methodology used by some LR 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.

  HNP has not used this simplified methodology to calculate fatigue usage, thus this RIS has no impact on HNP.

- RIS 2011-14 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. Westinghouse InfoGram IG-12-1 documents that Westinghouse was able to demonstrate that the calculations generated for the operating plants which use the WESTEMS™ program have not misused algebraic summation or the peak and valley options and have met all ASME Code limits.

  The Fatigue Monitoring AMP uses FatiguePro™ software to manage fatigue or cyclic loading. HNP does not use WESTEMS software, thus this RIS has no impact on HNP.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation and the relevant OE items are as follows.

- In June 2017 while reviewing the Unit 2 calculations for procedure, “Cumulative Fatigue Usage Factor Monitoring” an error was identified in the counting of start-ups and SCRAMS for the period covering 2013-2014. The calculation error was in the 60-year feedwater piping cumulative fatigue usage factor section. For the year 2014, the calculation stated that no start-up or scram events occurred. This was in contrast to the calculation tables which used two start-ups and SCRAM for the 60-year calculation.

  In response to this error, HNP expanded the scope for the 2015-2016 analysis that was currently being performed to include a recalculation of the 2013-2014 fatigue cycles. FatiguePro™ was used to analyze compressed desirable threshold (CDT) data files for 2013-2016. The resulting fatigue usage factor was acceptable through the end of the PEO. Thus, there was no operability concern due to this calculation error.

- In November 2022, an AMP effectiveness review was conducted for the Component Cyclic or Transient Limit Program. The review objectives for this effectiveness review included commitment management, implementing activity completion and results documentation, aging effects, correction actions, and OE. LR commitment documentation, LR inspection activities and results, as well as implementation of preventive actions were some of the areas the effectiveness review intended to verify.

  The AMP effectiveness review concluded that the Component Cyclic or Transient Limit program is effective, and that license renewal intended functions will continue to be maintained consistent with the CLB for the PEO.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The Fatigue Monitoring 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.2.2.3 Neutron Fluence Monitoring

Program Description

The Neutron Fluence Monitoring AMP is a new condition monitoring program that monitors and tracks neutron fluence (integrated, time-dependent neutron flux exposures) to RPV and reactor vessel internal (RVI) components to ensure that applicable RPV neutron embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessments for reactor internal components will remain within their applicable limits.

The Neutron Fluence Monitoring AMP will verify 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 AMP will ensure the analyses involving neutron fluence inputs continue to meet the appropriate limits defined in the CLB.

Monitoring will be performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in reports approved by the NRC. For fluence monitoring activities that apply to the beltline region of the RPV, the calculational methods will be performed in a manner that is consistent with the RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." Additional justification will be used as necessary for neutron fluence monitoring, regarding methods that are applied to RPV locations outside of the beltline region of the vessels or to reactor internal components.

The methods and assumptions for determining RPV neutron fluence for the beltline region will be consistent with RG 1.190. The methods and assumptions used for determining neutron fluence in the beltline region will include additional justifications as appropriate for the beltline regions significantly above and below the active fuel region of the core and for RVI components.

Neutron Fluence calculations will be performed using Radiation Analysis Modeling Application (RAMA) methodology. This methodology has been used across the nuclear industry to develop fluence projections for RPV and RVI components. HNP used this methodology to determine 80-year neutron fluence projections for subsequent license renewal.

The Neutron Fluence Monitoring AMP results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for RPV components. This includes but is not limited to the neutron fluence inputs for the RPV upper-shelf energy analyses and pressure temperature limits analyses that are required to be performed in accordance with 10 CFR Part 50, Appendix G requirements. Comparisons to the neutron fluence inputs for other analyses may include those for mean reference nil-ductility temperature (RT_{NDT}), and probability of failure analyses for RPV circumferential and axial shell welds, core reflood design analyses, and aging effect assessments for reactor internals that are induced by neutron irradiation exposure mechanisms.

HNP conditions that do not meet the acceptance criteria or 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 AMP, provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in technical specifications or in specific regulations of 10 CFR Part 50 apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

NUREG-2191 Consistency

The Neutron Fluence Monitoring AMP will be consistent without exception to the 10 elements of NUREG-2191, Section X.M2, “Neutron Fluence Monitoring."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. Several examples of this are the following:

- Shroud indications attributed to intergranular stress corrosion cracking (IGSCC) have been reported at many utilities in both the horizontal and vertical welds. HNP Unit 1 (2008, 2010, and 2014), HNP Unit 2 (2015) and Brunswick Unit 1 (2012) have reported inside diameter shroud indications which run outside the heat affected zone and at "off-axis" angles, which could be attributed to irradiation assisted stress corrosion cracking (IASCC). HNP Unit 1 and Brunswick Unit 1 also reported through-wall “off-axis” shroud cracking in 2014 and 2016 respectively. The Boiling Water Reactor Vessel Internals Project (BWRVIP) formed a Shroud IASCC Focus Group which has documented HNP's experience, along with a few other similar experiences, gathered survey information regarding industry shroud fluence estimates, and in 2015 performed material analyses on a HNP Unit 1 Shroud boat sample to gather further information regarding the cause of these indications and provide further industry guidance. A shroud off-axis cracking interim guidance was issued to require a one-time inspection for off-axis cracking and provide detailed evaluation guidance specifically for off-axis shroud flaws.

  HNP provided material to the BWRVIP focus group to assist the industry in determining further guidance. HNP also performed baseline inspections of shroud welds during spring 1996 thru spring 1999 refueling outages.

- EPRI requested information from the Southern Nuclear Company (SNC) operating fleet regarding use of procedures provided by the NRC in NUREG-0800 Branch Technical Position (BTP) 5-3, "Fracture Toughness Requirements."

  HNP provided the requested information to EPRI via email and in person meetings to assist the industry in developing a position and establishing safe practices for fracture toughness requirements. This information included HNP adjusted reference temperature (ART) tables and methodology for estimating fracture toughness for non-beltline material and nozzle forging.

- NRC Regulatory Issue Summary (RIS) 2014-11 - "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components" provided industry guidance on the scope and detail of information that should be provided in the reactor vessel fracture toughness and associated pressure-temperature (P-T) limits licensing applications to facilitate staff review.

HNP response was to review the guidance and determine the impact to the fleet. It was determined that HNP had recently prepared a pressure temperature limit report (PTLR). This PTLR used an NRC methodology that had been recently approved which incorporated the guidance from RIS 2014-11.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows.

- In March 2016, BWRVIP 2016-030, "Core Shroud Off-Axis Cracking Interim Inspection and Evaluation Guidance," was reviewed for impact to HNP. This review determined that the guidance did not impact HNP bases documents. However, this guidance did require a change to current HNP shroud guideline procedure.

  HNP shroud guideline procedure was updated with the core shroud interim guidance.

- In October 2016, this technical evaluation acknowledged receipt of BWRVIP-25 Revision 1 and BWRVIP-100 Revision 1. The changes that were implemented in Revision 1 of BWRVIP-25 provided a generic criterion which could be used to eliminate the requirement for inspection of core plate bolts, as well as a plant specific structural analysis method which may be used to eliminate inspection requirements.

  HNP Unit 1 and Unit 2 are exempt from core plate bolt inspection requirements because the installed tie rod repair designs on both units included installation of core plate wedges, which provide redundant support to the core plate bolts. Due to this exemption, the changes within BWRVIP-25 Revision 1 are not applicable to HNP.

  BWRVIP-100 Revision 1, "Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Core Shrouds," provided fracture toughness limitations that should be used for design and flaw evaluations. This revision expanded guidance to materials with fluence higher than $3x10^{21}$ n/cm^2.

  This guidance was incorporated into HNP vessel and internals program procedures.

- In January 2020, a HNP Unit 1 fluence assessment report presented the results of the RPV, core shroud, repair tie rod assemblies, and jet pump fast neutron fluence evaluations that were performed by TransWare Enterprises for HNP. The fast neutron fluence presented in this report was determined in accordance with the guidelines and requirements presented in NRC RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." Fluence is presented for the 0T, 1/4T and 3/4T depths in the RPV plates, welds, and nozzles throughout the RPV beltline region. The HNP Unit 1 fluence evaluations provided in this report were based on historical operating conditions for the reactor. The fluence evaluations were presented at the End of Cycle (EOC) 28 (33.9 EFPY) and projected to 49.3 Effective Full Power Years (EFPY) of reactor operation. The fluence evaluations were performed based on the RAMA Fluence Methodology.

Neutron fluence evaluations described in this report met the requirements of Appendices G and H of 10 CFR Part 50 and NRC RG 1.190. This assessment provided objective evidence that HNP monitors and tracks fluence during plant operations.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Neutron Fluence 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 periodically evaluated.

Conclusion

The Neutron Fluence Monitoring 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 NUREG-2191 Chapter XI Aging Management Programs

B.2.3.1 ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD (ISI) aging management program (AMP) is an existing program where inspections identify and correct degradation in ASME Code Class 1, 2, and 3 components. In accordance with 10 CFR 50.55a, the ISI program plan documenting the examination and testing of Class 1, 2 and 3 components are prepared in accordance with the rules and requirements of ASME Code Section XI, 2007 Edition and Addenda through 2008 as supplemented by NRC approved ISI alternatives.

This AMP describes the long-term inspection program for Class 1, 2 and 3 components. The ISI AMP includes Class 1, 2 and 3 pressure-retaining components, and their integral attachments. 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 ISI AMP identifies and corrects degradation in Class 1, 2, and 3 components. 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 have been in place since initial operation of the plant and the inspections are conducted as part of the ISI AMP based on the current ISI 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 ISI program documents are updated at the end of each 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 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 ISI AMP is consistent without exception to the 10 elements of NUREG-2191, XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

- Inspection and Enforcement Bulletin (IEB) 80-13: Cracking in core spray (CS) 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 CS 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.

The OE for the HNP internals was reviewed. Over time there have been several occurrences of cracking, all of which have been repaired or are currently being monitored in accordance with prescribed procedures and programs. Early in life, IGSCC was detected on the Unit 1 CS sparger. It was repaired by installation of a mechanical clamp. The sparger has been full flow tested and the clamp examined afterward with no evidence of degradation. Multiple indications have been detected over the years on the NSR steam dryers. Some have been repaired while others are monitored.

- GL 94-03: IGSCC has also occurred in several core shrouds in BWRs. 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 are 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 BWR Owners' Group on coordination of inspections, evaluations and repair options for all BWR internals susceptible to IGSCC.

Crack-like indications were detected in the core shrouds for both units. SNC conservatively decided to install preemptive repairs to eliminate the concern of cracking in shroud circumferential welds. The repair hardware and vertical welds are periodically examined as specified in the BWRVIP.

<u>Plant Specific Operating Experience</u>

The ISI AMP has been effective at providing assurance that the effect of aging is managed so that the intended functions of the components within the AMP scope are consistent with the CLB throughout the SPEO. A review of OE supports the above statement as most corrections are related to identifying degraded conditions and providing corrective actions to restore the system performance to acceptable conditions as described in the CLB.

ISI programs and plans are being used and the controlling procedures refer and adhere to the ASME Section XI Code. Overtime, the program has proven to be an effective method of managing the effects of aging in Class 1, 2 and 3 pressure-retaining components, and their integral attachments.

Review of plant-specific OE also indicates that the ISI program is performing its function of managing aging effects. A review of corrective action reports from February 1, 2013, through January 31, 2023, was performed. The ISI program provided 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.

A recent HNP OE search was performed for SLR which covers the last 10 years of operation and the relevant OE items are as follows.

- In September 2014, SNC ISI program owners learned through ISI Program personnel at another licensee’s PWR facility of a potential issue regarding a failure to include the CRDM restraints under their ISI Program for examination based on NRC questions. Based on a review of the HNP FSAR Sections 4.5 and 5.4.6.3.5, the design function of the CRD housing supports is to prevent a nuclear transient in the unlikely event that there is a CRD housing failure. The evaluation determined that the CRD housing supports do not meet the definition of a support that would require examination under the ISI Program.

- In March 2015, ISI alternative HNP-ISI-ALT-08-02, Version 1.0 was developed to install weld overlays on selected dissimilar metal welds (ASME Category B-F) at both HNP units. The NRC approved this alternative for the fourth ISI interval. During the Unit 2 spring 2015 outage, a feedwater weld was overlaid due to inspection issues associated with this Inconel weld. An adequate ultrasonic examination was not possible for this weld due to the adjacent piping weld and base material being overlaid plus a taper on the opposite side of the weld. The ISI alternative provides for three specific liquid penetrant examinations to be performed prior to, during the weld overlay process, and when the weld overlay has been completed when a buffer layer is installed. In addition, an ultrasonic examination was performed on the final weld overlay and no other examinations are needed. The alternative approach was approved by the NRC in June 2009 and was approve for use in the fifth 10-year interval.

- In April 2015, HNP found two weld overlays which were installed in 1988 did not have the typical full structural weld overlay that extended over the dissimilar metal weld and covered portions of both the austenitic safe-end and the ferritic nozzle. The two overlays met ASME code requirements, however, the welds were not examined in 1997 as required by NUREG-0313 requirements. The requirements of NUREG-0313 were changed and BWRVIP-75 was published following the 1997 timeframe which resulted in different examination requirements. These newer requirements have been met after 1997. The welds were examined during the fifth ISI interval and HNP determined the welds meet the ASME code requirements.

- In November 2015, while performing HNP Unit 1 spring 2016 outage activities, a low EVT-1 examination coverage was documented for lower core shroud/shroud support vertical welds. The spring 2016 outage report documents 0 percent EVT-1 exam coverage for each of these welds, and states that a “best effort” exam was conducted. Although inspection quality does not meet BWRVIP-03 Revision 10 quality requirements to credit EVT-1 for these inspections, the best effort exams are VT-1 quality, which is an exam defined and accepted in ASME Section XI code. VT-1 inspection coverage from the spring 2016 outage for these welds was similar to 2004 and 2010 inspection results. No indications have ever been reported for these welds.

- In April 2019, HNP used the BWRVIP guidance in lieu of ASME Section XI Category B-N-2. Upon review of the guidance, it was noted the examinations mis-characterizes an exam type and exam frequency specified by BWRVIP-38, specific to HNP Unit 2. Due to the unique design of the Unit 2 shroud support-to-RPV weld and core support structures, BWRVIP-38 specifies a more general examination for this HNP Unit 2 component. HNP communicated the discrepancy with the NRC. The discrepancy was corrected and approved by the NRC.

- In February 2020, it was noted that during ultrasonic examination of the RPV closure head dollar plate weld that several embedded fabrication type flaws were discovered. These flaws were evaluated to the tables in ASME XI 2007, including the 2008 Addenda, and found the flaws to be unacceptable. HNP performed an analytical evaluation and determined the flaw was acceptable per ASME Section XI IWB-3600.

- In January 2019, two dissimilar metal welds were removed from the outage scope to perform ultrasonic examinations of welds in accordance with EPRI Report 3002007786 and NEI-03-08 guidance. To accomplish the required inspection weld circumference, HNP discussed adding weld material, a weld overlay the applicable welds, or an alternate solution such as a technical justification for the exam limitations. A reassessment, using encoded examinations with tools that were not available previously, of the surface condition was performed and determined that the surface condition would need repair to achieve adequate examination coverage per EPRI guidelines. HNP repaired the weld reexamined the welds following EPRI and NEI guidance and determined the weld satisfactory.

- In December 2023, it was noted that three additional SGSCC Category D welds in Unit 2 were to be investigated for pre-emptive mitigation/repair/replacement to reduce future examination costs. Additionally an update to the applicable AMP and Heat Map to accurately reflect their current vulnerability due to limited access. These Category D welds are dissimilar metal welds that contain SGSCC susceptible material, have not been effectively mitigated using a stress improvement method, and are not protected by Hydrogen Water Chemistry. These welds are currently volumetrically examined at

3 welds/6 yrs by Phase Array, if repaired by weld overlay using IGSCC resistant material, future examinations can be reduced to 1 weld/10 years.

These examples demonstrate that the inspections executed under the ISI AMP scheduled/opportunistic inspections, and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The ISI 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 periodically evaluated.

Conclusion

The ISI 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.2.3.2 Water Chemistry

Program Description

The Water Chemistry AMP, previously known as the Reactor Water Chemistry Control, Fuel Pool Chemistry Control, and Demineralized Water and Condensate Storage Tank Chemistry Control AMPs, 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 environment. The Water Chemistry AMP relies on monitoring and control of reactor water chemistry based on industry guidelines contained in BWRVIP-190 Revision 2 (Reference 1.6.17).

The 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 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 reasonable assurance that significant degradation is not occurring, and the component intended function is maintained during the SPEO. For these specific cases, the One-Time Inspection AMP (Section 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 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, reduction of heat transfer, and cracking. Additives are used 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 consistent with BWRVIP-190 Revision 2.

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 BWRVIP-190 Revision 2.

NUREG-2191 Consistency

The Water Chemistry AMP is consistent with an exception to the 10 elements of NUREG-2191, Section XI.M2, “Water Chemistry.”

Exceptions to NUREG-2191

The Water Chemistry AMP includes the following exception to the NUREG-2191 guidance:

Exception 1. Elements 3, 5, and 6

The EPRI Water Chemistry guidelines referenced in NUREG-2191 are contained in BWRVIP-190 Revision 1 (EPRI-3002002623). Hatch has evaluated and adopted the relevant guidance in BWRVIP-190 Revision 2 (EPRI-3002025550).

Justification for Exceptions

The latest EPRI Water Chemistry guidelines reflects the latest technical bases for ensuring high purity water in nuclear systems and applicable industry operating experience. Revision 2 of BWRVIP-190 requires additional sampling and analysis of RCS and Condensate with a more-conservative stance versus the analysis requirements and acceptance criteria contained in Revision 1 of BWRVIP-190. Therefore, adoption of Revision 2 of BWRVIP-190 provides greater assurance that high purity water is maintained at HNP.

Enhancements

None.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per a site procedure and takes appropriate corrective actions. Examples of this are as follows:

- At a separate facility, elevated sulfate levels were seen in reactor water chemistry due to an epoxy coating used for the reactor makeup tank. It was determined that this issue is not a concern at HNP because this particular coating is not used in systems connected to the nuclear boiler system. The condensate storage tanks are used for reactor makeup and are uncoated.

IGSCC has occurred in small and large diameter BWR piping made of austenitic stainless steels and nickel-base alloys. Significant cracking has occurred in recirculation, core spray, residual heat removal systems, and reactor water cleanup system piping welds. IGSCC has also occurred in a number of vessel internal components, including core shroud, access hole cover, top guide, and core spray spargers (NRC IEB 80-13, NRC IN 95-17, NRC GL 94-03, and NUREG-1544). No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported (NUREG/CR–6001).

HNP utilizes an online noble chemistry (OLNC) assisted hydrogen water chemistry (HWC) system in which hydrogen is injected into feedwater to reduce the level of dissolved oxygen in the reactor coolant. The reduction of dissolved oxygen in combination with high water quality reduces or eliminates IGSCC in primary system piping and improves the resistance to IGSCC in vessel internal components.

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.

Plant Specific Operating Experience

The 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 abnormal chemistry results have occurred during operational transients such as startups or as a result of equipment issues causing air inleakage. Although the abnormal conditions are expected during these transients, the CAP is used for documentation.

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 over the last 10 years 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. Condition Reports 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.

- In April 2014, EPRI issued revision 1 of BWRVIP-190. HNP evaluated the changes to these water chemistry guidelines and updated the site chemistry procedures to reflect the changes.
- In October 2019, a degraded solenoid valve led to inleakage into Unit 2 condensate system. Upon repairing solenoid valve, dissolved oxygen concentration returned to levels within the EPRI limit.
- In July 2020, a Unit 1 suppression pool sample was pulled and corrected conductivity, chlorides, and sulfates were above the EPRI limits. The system was fed and bled with increased sampling frequency until the parameters remained below the EPRI limits with downward trends.

- In May 2024, EPRI issued revision 2 of BWRVIP-190. HNP evaluated the changes to these water chemistry guidelines and updated the site chemistry procedures to reflect the changes.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

These examples demonstrate that the program activities executed under the Water Chemistry AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

Conclusion

The 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

Program Description

The Reactor Head Closure Stud Bolting AMP is a new preventive and condition monitoring program that will include ASME Code, Section XI examinations of reactor head closure studs, flange threads, and associated nuts, washers, and bushings to manage cracking and loss of material. The Reactor Head Closure Stud Bolting AMP will manage these aging effects in an air-indoor uncontrolled environment. The AMP will use ISI examination requirements specified in the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and preventive measures recommended within NRC RG 1.65 Revision 1. These preventive measures include not using metal-plated stud bolting, using manganese phosphate or other acceptable surface treatments, and using stable lubricants.

The Reactor Head Closure Stud Bolting AMP will manage 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 will be accomplished through effective volumetric testing, visual and surface monitoring techniques, acceptance criteria, corrective actions, and administrative controls.

The Reactor Head Closure Stud Bolting AMP uses the inspection schedule of IWB-2400 and the extent and frequency of Table IWB-2500-1 to detect cracks, loss of material, and leakage. HNP will examine reactor vessel threads in flange, reactor head closure studs, nuts, and washers during refueling outages in accordance with the ISI AMP. Reactor head closure studs will be examined during refueling outages by volumetric testing in accordance with ASME Section XI requirements. The ISI program will specify the inspection schedule and extent of examination, which is consistent with ASME Section XI, IWB-2400.

Appropriate preventive measures will be used for the reactor closure stud bolting based on site OE and best practices. HNP will continue existing preventive measures that include procedural requirements to preclude the use of molybdenum sulfide-containing lubricants. Procedures will also ensure procurement requirements for replacement of reactor head closure stud material maintains a maximum yield strength of less than 150 ksi or ultimate tensile strength not exceeding 170 ksi.

This AMP will ensure the frequency and scope of examination of the reactor head closure stud bolting is sufficient such that the aging effects are detected before the components intended function would be compromised or lost. Inspections will be performed in accordance with the inspection intervals specified by the ISI plan.

The acceptance criteria associated with this AMP will be 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 will be performed to determine if the component is acceptable for continued service. Repair and replacement of items that do not meet acceptance standards will be performed in accordance with the requirements of IWA-4000. Evaluations will be performed for test or inspection results that do not satisfy established criteria. A condition report will be initiated to document the condition in accordance with the CAP.

NUREG-2191 Consistency

The Reactor Head Closure Stud Bolting AMP will be consistent with one exception to the 10 elements of NUREG-2191, Section XI.M3, "Reactor Head Closure Stud Bolting."

Exceptions to NUREG-2191

<u>Exception 1. Element 2, Preventive Actions</u>

NUREG-2191 recommends, as a preventive measure that can reduce the potential for SCC, that the existing bolting material for the reactor head closure studs have an ultimate tensile strength limited to less than 170 ksi.

Hardness tests conducted on the reactor vessel closure studs have showed that some studs have greater than 170 ksi tensile strength. Therefore, an exception has been taken to the NUREG-2191 XI.M3, Element 2(d) recommendation that bolting material for the reactor head closure studs have an ultimate tensile strength limited to less than 170 ksi.

Justification for Exceptions

This exception is acceptable because HNP will meet all other preventive measures listed in NUREG-2191 AMP XI.M3, "Reactor Head Closure Stud Bolting" that can reduce the potential for cracking with the new Reactor Head Closure Stud Bolting AMP. In addition, volumetric examinations that are capable of detecting degradation due to SCC are currently being conducted and will continue to be performed in accordance with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP as applicable.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. An example of this is the following:

- NRC IN 2012-21, “Reactor Vessel Closure Head Studs Remain Detensioned During

Plant Startup" pertains to detensioned head studs at the Brunswick Unit 2 boiling water reactor. During reactor reassembly from an outage, the head was not sufficiently tightened. The root cause was ambiguous instructions for using the stud tensioner tool, which led to leakage from the reactor head flange almost immediately during plant startup.

HNP's response to this IN is captured in a technical evaluation. HNP performed a review of their stud tensioning instructions to identify any gaps or ambiguity that could potentially lead to a similar event. As a result, various revisions were made to plant procedures to clarify and reinforce critical data points as well as add cold leakage tests whenever the reactor head is removed.

<u>Plant Specific Operating Experience</u>

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. The relevant OE items are as follows.

- During the spring 2017 refueling outage at HNP Unit 2 ISIs were performed on all RPV head studs. A volumetric examination discovered an indication on stud #33 below the vessel flange at the threads. During this outage and prior to the Spring 2025 outage, the stud was unable to be removed. During the time that the stud was unable to be removed, SNC requested and received multiple relief requests from the NRC since 2017 for surface examinations. SNC provided the NRC justification for having two studs in HNP Unit 2 and one stud in HNP Unit 1 being less than fully tensioned in the Dominion Engineering, Inc. calculation included with the licensing amendment requests (LAR) for relief. A more detailed discussion of the aforementioned process is included in ML19035A550. Additionally, HNP has received license amendments 322 and 267 for Units 1 and 2 respectively for the approval of a LAR to relax the required number of fully tensioned RPV head closure studs. The approval of this LAR ensures that HNP can be operated safely if circumstances arise that result in the need to operate Units 1 and 2 with a head closure stud(s) not fully tensioned. This LAR approval was issued in April 2024 and additional details can be found in ML23032A332. In the Spring 2025 outage, Unit 2 stud #33 was removed and an analysis demonstrates that the remaining closure studs along with the RPV can perform their intended functions with this stud removed.

- Nuclear Oversight (NOS) audit reports verify compliance and the effectiveness of SNC's QA Program. NOS audit reports were reviewed for 2014-2022 and included review of AMPs for ISI and BWRVIP. These two areas are related to the Reactor Head Closure Stud Bolting AMP in the initial LR. During the periods reviewed, there were no significant findings that would impact the Reactor Head Closure Stud Bolting AMP.

- In September and October of 2020, a focused self-assessment was conducted to evaluate plant Hatch BWRVIP program (implements closure stud license renewal requirements) for (1) standards compliance and (2) industry excellence. This included a review of procedures to compare against applicable BWRVIPs and other guidance as well as a review of reactor vessel inspections. There were no findings or areas for improvement noted that would impact the Reactor Head Closure Stud Bolting AMP.

- An ISI self-assessment was conducted in October 2021. Several documents, including procedures and condition reports were reviewed during the assessment. There were no findings or areas for improvement noted that would impact the Reactor Head Closure Stud Bolting AMP.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Reactor Head Closure Stud Bolting 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 periodically evaluated.

Conclusion

The Reactor Head Closure Stud Bolting 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.2.3.4 BWR Vessel ID Attachment Welds

Program Description

The BWR Vessel ID Attachment Welds AMP is an existing AMP that manages cracking due to cyclic loading, SCC and SCC for BWR vessel ID attachment welds. This program is a condition monitoring program for detecting cracking due to SCC, IGSCC, and cyclical loading mechanisms in the reactor vessel inside diameter (ID) attachment welds of BWRs. The program includes non-destructive techniques such as VT-1, EVT-1 and VT-3 visual examination methods to determine the general mechanical and structural condition of the reactor vessel interior attachments and flaw evaluation in accordance with the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, and the guidance in “BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” BWRVIP-48 Revision 2 to provide reasonable assurance of the long-term integrity and safe operation of BWR vessel ID attachment welds. The examination scope, frequencies, and methods are in accordance with ASME Code, Section XI, Table IWB-2500-1, Examination Category B-N-2, applicable NRC approved ASME Code alternatives, and BWRVIP-48 Revision 2. The BWR Vessel ID Attachment Welds program is part of the ASME Section XI Inspection Program and therefore will be updated periodically in accordance with 10 CFR 50.55a. The BWR Vessel ID Attachment Welds AMP also uses water chemistry control, and repairs when required. The water chemistry program monitors and maintains a high water purity which reduces the susceptibility to SCC or IGSCC.

The guidance in BWRVIP-48 Revision 2 includes inspection recommendations and evaluation methodologies for certain attachment welds between the vessel wall and the brackets that attach components to the vessel. In some cases, the attachment is a weld attached directly to the vessel wall; in other cases, the attachment includes a weld build-up pad on the vessel wall. The BWRVIP-48 Revision 2 report includes information about the geometry of the vessel ID attachments; evaluates susceptible locations and the safety consequence of failure; provides recommendations regarding the method, extent, and frequency of augmented examinations; and discusses acceptable methods for evaluating the significance of structural integrity indications detected during examinations. Additional inspections and evaluation of the core spray piping brackets are performed in accordance with BWRVIP-18 Revision 2-A. Additional inspections and evaluation of the jet pump riser brace are performed in accordance with BWRVIP-41 Revision 4-A.

HNP will perform ongoing implementation of the existing BWR Vessel ID Attachment Welds program for managing the effects of aging for applicable components during the SPEO.

NUREG-2191 Consistency

The BWR Vessel ID Attachment Welds AMP is consistent with exceptions to the 10 elements of NUREG-2191, Section XI.M4, "BWR Vessel ID Attachment Welds AMP."

Exceptions to NUREG-2191

The BWR Vessel ID Attachment Welds AMP includes the following exception to the NUREG-2191 guidance:

Exception 1. Elements 1, 3, 4, 5, and 6

The BWR Vessel ID Attachment Welds AMP guidelines for weld inspection and flaw evaluation are in accordance with BWRVIP-48 Revision 2 (EPRI 3002018321), in lieu of the NUREG-2191 revision specified, BWRVIP-48-A, 2004.

Justification for Exceptions

The HNP BWR Vessel ID Attachment Welds aging management program is based on the inspection, evaluation, and repair guidelines contained in BWRVIP-48 Revision 2, rather than BWRVIP-48-A as specified in NUREG-2191. Per BWRVIP-94, Revision 4, “Program Implementation Guide,” when BWRVIP guidelines are approved by the Executive Committee and are initially distributed, or subsequently revised, each utility shall modify their vessel and internals program documentation to reflect the new requirements and shall implement the guidelines within two refueling outages, unless a different schedule is identified by the BWRVIP at the time of document distribution. If new guidelines approved by the Executive Committee includes revisions to NRC approved BWRVIP guidelines (e.g., BWRVIP-48 Revision 2 revised the guidelines contained in BWRVIP-48-A), and the revised guidelines are less conservative than those approved by the NRC, these less conservative guidelines shall be implemented only after the NRC reviews and approves the changes. “NRC approved” generally means the document was submitted to the NRC for review and approval and a final Safety Evaluation Report (SER) has been issued and is incorporated into publication of a “-A” document or equivalent. Alternatively, if the revised guidelines are screened out from submittal to the NRC in accordance with NEI 03-08, “Guidelines for the Management of Materials Issues,” Appendix C, utilities may implement the revised guidelines subject to any licensing restrictions at the site (e.g., commitments to use previous revisions under license renewal or with ASME Code relief requests). Revision 2 of BWRVIP-48 received a screening evaluation performed in accordance with Appendix C of NEI 03-08, Rev. 4, “Document Screening.” The evaluation considered all of the elements typically included within inspection optimization evaluations (i.e., field performance, NDE capability, residual stress state, and flaw tolerance), included a level of rigor consistent with prior inspection optimization evaluations and applied risk principles consistent with precedent inspection optimization evaluations used to provide technical bases for modifications to inspection program requirements. It was noted that the general methodology was consistent with the approach taken to optimize BWRVIP requirements for other reactor internals components found not to have significant SCC susceptibility. The screening evaluation concluded that BWRVIP-48 Revision 2 could be generically released for implementation by the United States BWRVIP members without prior NRC review and approval. The Qualitative Risk Assessment performed per Appendix C of NEI 03-08, Revision 4, is documented in Section G.4 of BWRVIP-48 Revision 2.

The inspection requirements for reactor vessel ID attachment welds contained in BWRVIP-48-A were originally based on the potential susceptibility of attachment welds to SCC given the existing state of knowledge. At the time that BWRVIP-48 was initially issued (1998), SCC of BWR internals was still largely in a discovery phase, with the frequency and ultimate extent of cracking largely unknown. As a result, the inspection program specified by BWRVIP-48 was purposely conservative. Over twenty years have elapsed since the initial issue of BWRVIP-48, and it was therefore reasonable for the BWRVIP to revisit the inspection requirements in BWRVIP-48-A based on the current state of knowledge regarding performance in the field and understanding of the progression of SCC in BWRs, resulting in the issuance of BWRVIP-48 Revision 2.

The changes in inspection scope and frequency between BWRVIP-48 and BWRVIP-48 Revision 2 are shown in the table below, as well as ASME Code Section XI IWB Inspection requirements and additional relevant BWRVIP inspection guidance:

Component	ASME Code Section XI IWB Inspection Requirement,[3,4]	BWRVIP-48-A Interval	BWRVIP-48 Rev 2 Interval	BWRVIP-41 Rev 4-A Interval[1]	BWRVIP-18 Rev 2-A Interval[2]
Core Spray Piping Bracket Attachment	B-N-2, VT-3 @ 100% every 10 years	EVT-1 @ 100% every four outages	EVT-1 @ 25% every 12 years	N/A	EVT-1 @ 100% every 10 years
Steam Dryer Support Bracket Attachment	B-N-2, VT-3 @ 100% every 10 years	EVT-1 @ 100% every 10 years	EVT-1 @ 100% every 12 years	N/A	N/A
Jet Pump Riser Brace Attachment	B-N-2, VT-1 @ 100% every 10 years	EVT-1 @ 25% every 6 years	EVT-1 @ 25% every 12 years (HWC)	EVT-1 @ 25% every 12 years	N/A

1. BWRVIP-41 Rev 4-A provides inspection and evaluation guidance for the jet pumps and further address the jet pump riser brace attachment welds.

2. BWRVIP-18 Rev 2-A provides inspection and evaluation guidance for the core spray piping within the reactor vessel and further address the core spray piping bracket attachment welds.

3. HNP has an approved Alternative HNP-ISI-ALT-05-04 for use of BWRVIP Documents in lieu of B-N-1 and B-N-2 Section XI requirements.

4. Other B-N-2 RPV attachment weld inspections performed in accordance with ASME Code Section XI IWB Inspection requirements include steam dryer holddown brackets, guide rod brackets, feedwater sparger brackets and surveillance sample holder brackets.

The components that are currently being inspected at a frequency less than that specified in the ASME Code or BWRVIP-48-A are listed in the table above. When periodic inspections specify that only a fraction of the population is required during the specified interval, HNP selects attachment welds based on accumulated service time since the weld was last inspected. Weld selection is rotated through the entire population before any specific weld is selected a second time for periodic inspections. For all other B-N-2 attachment welds, BWRVIP-48 Revision 2 does not specify any periodic inspections in addition to those specified in ASME Section XI, so these inspections are performed in accordance with ASME Code Section XI IWB Inspection Requirements.

Examination history at HNP Unit 1 and 2 of vessel ID attachment welds listed in the above table was reviewed to assess whether site-specific data was reflective of the data identified in the conclusions drawn from the qualitative risk assessment in BWRVIP-48, Revision 2, Appendix G. HNP has performed all required inspections of vessel ID attachment welds to-date, with no relevant indications observed at any location. This review confirms that the data collected by EPRI is comparable to the specific results at Hatch and supports the technical justification in the qualitative risk assessment of BWRVIP-48, Revision 2, Appendix G.

The qualitative risk assessment in BWRVIP-48 Revision 2, Appendix G, Section G.4 determined that there is not a significant change in risk associated with the proposed changes to inspection requirements. The potential for SCC occurrence in vessel ID attachment welds is now known to be far lower than what was assumed based on the limited set of inspection data available at the time BWRVIP-48 was initially developed. The initial requirements also did not provide guidance for managing the potential for fatigue cracking. The addition of one-time inspection requirements and the updated scope expansion requirements are key improvements to the program that support the proposed optimization of periodic inspection requirements. Therefore, it is concluded that there is not a substantial change in risk associated with the new recommended requirements in BWRVIP-48 Revision 2.

It can therefore be concluded that the review of the qualitative risk assessment performed in BWRVIP-48, Revision 2 and the site specific data acquired at HNP demonstrate that the analysis is applicable to HNP Units 1 and 2. Usage of BWRVIP-48 Revision 2 in lieu of BWRVIP-48-A provides a reasonable assurance of safety and does not challenge the quality of the BWR Vessel ID Attachment Welds program.

Enhancements

None.

Operating Experience

Industry Operating Experience

Review of the last two LRA/SLRAs submitted with a discussion of BWR Vessel ID Attachment Welds identified the following:

- The NRC issued a LR applicant action items based on its review of BWRVIP-48. These action items required:
    - Verification that the plant is bounded by BWRVIP-48 and commitment to manage the effects of aging on the functionality of the bracket attachments during the SPEO.
    - Ensuring programs and activities specified in BWRVIP-48 are described in the FSAR.
    - Ensuring the inspection strategy in BWRVIP-48 does not conflict with technical specifications.

- The above bullets were dispositioned for Peach Bottom in SLRA Appendix C. HNP verified that HNP is bounded by BWRVIP-48. HNP action items related to BWRVIP-48 will be documented in the HNP SLRA Appendix C; therefore, no further actions are required.

HNP evaluates industry OE items for applicability and takes appropriate corrective actions.

- Per GL 94-03, IGSCC has also occurred in a number of core shrouds in BWRs. 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 are 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. Crack-like indications were detected in the core shrouds for both units. SNC conservatively decided to install preemptive repairs to eliminate the concern of cracking in shroud circumferential welds. The repair hardware and vertical welds are periodically examined as specified in the BWRVIP.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In November 2015, while performing HNP Unit 1 spring 2016 outage activities, a low EVT-1 examination coverage was documented for lower core shroud/shroud support vertical welds. The spring 2016 outage report documents 0 percent EVT-1 exam coverage for each of these welds, and states that a "best effort" exam was conducted. Although inspection quality does not meet BWRVIP-03 Revision 10 quality requirements to credit EVT-1 for these inspections, the best effort exams are VT-1 quality, which is an exam defined and accepted in ASME Section XI code. VT-1 inspection coverage from the spring 2016 outage for these welds, would likely range between 90-100 percent coverage, similar to 2004 and 2010 inspection results. No indications have ever been reported for these welds.

- In February 23, 2016 during the HNP Spring 2016 Refueling Outage, RPV internals visual examination of inside surface of shroud horizontal weld H-4 from vacated fuel cells at 50-35, 50-31, 50-27, 50-23 and 50-19 discovered transverse indications coming off of the existing horizontal indications adjacent to H-4. These flaws were determined to be typical IGSCC flaws within the heat affected zone. These flaws were bounded by an existing flaw evaluation and calculation and were determined to be acceptable for continued service.

- On February 14, 2017 during RPV internals visual examinations, linear indications were observed on the shroud side of the heat affected zone of the top guide hold-down bracket. The functional evaluation concluded no mitigating action was needed and indefinite continued operation was acceptable since the safety function of the shroud and top guide is not affected by the indication. The indications were in the heat affected zone of a weld and mostly likely caused by

IGSCC.

- During the 2018 Spring Refueling Outage of Hatch Unit 1, visual inspection of the steam dryer revealed new indications similar to indications already reported during the HNP Spring 2014 Refueling Outage. These indications are located in the heat affected zone and determined to be most likely caused by IGSCC. The steam dryer is a non-ASME code, non-safety class reactor internal component with no safety function and the vertical partition plate weld (VP 3/2-4) inspections are owner elected.

These examples demonstrate that the inspections executed under the BWR Vessel ID Attachment Welds AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function. During the SLR period, these examinations will be conducted in accordance with guidance of BWRVIP-48 Revision 2 in lieu of ASME Section XI requirements for Table IWB-2500-1, “Examination Categories B-N-1 and B-N-2.”

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The HNP 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 BWR Vessel ID Attachment Welds AMP provides reasonable assurance that the effects of aging are managed so that the intended function(s) of components within the scope of the AMP are maintained consistent with the CLB during the SPEO.

B.2.3.5 BWR Stress Corrosion Cracking

Program Description

The BWR Stress Corrosion Cracking AMP is an existing AMP that manages IGSCC in BWR coolant pressure boundary piping made of stainless steel, stainless steel cladded low alloy steel and nickel alloy components as delineated in NUREG–0313, Revision 2, and the NRC GL 88-01 and its Supplement 1. The AMP is applicable to all piping, piping components and piping welds made of austenitic stainless steel, stainless steel cladded low alloy 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 Stress Corrosion Cracking AMP is part of the NRC reviewed ASME Section XI Inservice Inspection Program and provides for condition monitoring of the material susceptible to BWR SCC in accordance with the applicable requirements of ASME Section XI, NUREG-0313, and NRC GL-88-01 guidance. This program is a condition monitoring program which also relies on countermeasures. The BWR Stress Corrosion Cracking AMP focuses on (1) managing and implementing countermeasures to mitigate IGSCC by maintaining high water purity which reduces susceptibility to SCC or IGSCC in accordance with the Water Chemistry AMP and (2) performing ISI to monitor IGSCC and its effects on the intended function of BWR piping components within the scope of this program.

The program detects and sizes cracks and detects leakage by using the examination and inspection guidelines delineated in ASME Section XI, NUREG-0313, Rev. 2, and NRC GL 88-01 as applicable. This program relies on the staff-approved positions that are described in NUREG–0313, Revision 2, and GL 88-01.

Modifications to the extent and schedule of inspection in NRC GL 88-01 are implemented in accordance with the inspection guidance in approved BWRVIP-75-A . This AMP utilizes BWRVIP-75-A for implementation of an augmented program that provides examination for detection of IGSCC per the Inservice Inspection Plan.

This program applies to the following systems:

- RPV
- Nuclear boiler
- Reactor recirculation

NUREG-2191 Consistency

The 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

HNP evaluates industry OE items for applicability per a site procedure and takes appropriate corrective actions. Examples of this are as follows:

- 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.

  HNP 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.

- In 2016, documentation of OE from Exelon Generation Calvert Cliff’s Unit 1 (CCU1) via industry emergent issue communication to various industry groups including; Primary Materials Management Program, Materials Reliability Program, Non-destructive

Examination Integration Committee, and the BWR Vessel and Internals Project was performed and evaluated. The OE concerned the detection of a significant change in examination results in an axial flaw in a pressurizer safety relief nozzle-to-safe-end dissimilar metal weld (DMW) that had been mitigated by Mechanical Stress Improvement (MSIP) process in 2006. The 4-inch DMW was being examined to meet ASME Code Section XI Code Case N-770-1 requirements as mandated and conditioned in 10 CFR 50.55a(g)(6)(ii)(F). An axial flaw previously characterized in 2006 and 2010 as 8 percent through thickness was characterized as 81.6 percent through-wall. The DMW had been mitigated by MSIP in 2006 based on the 8 percent reported flaw depth being less than the generic allowable flaw depth of 30 percent. Based on preliminary causal analysis, it is that ineffective MSIP or new flaw initiation and growth can be eliminated as potential causes. The third potential cause was considered most likely; that is, the previous examinations did not detect (2006) the extent of the axial flaw or properly characterize as connected, the two flaws that were reported.

The OE is applicable to HNP since HNP has 29 welds that have been stress improved on Unit 1 and 17 welds on Unit 2 by the MSIP process.

- Receipt of OE from Susquehanna Unit 1 via a BWRVIP Emergent Issue Call on 6/20/2016. Susquehanna Unit 1 was shut down on 6/6/16 due to elevated and increasing drywell leakage (0.5 gpm). During the investigation of the unidentified leakage, a through-wall indication was found in the 2-inch outside diameter (OD), 0.2" thick, SA-182 Type 304 pipe above the flange on the local power range monitor (LPRM) 24-09 housing, which is an ASME Class 1 component. Leakage from the through-wall indication was approximately 60 dpm at pressure. However, leakage from the LPRM was not the major source of the unidentified leakage. Ultrasonic testing (UT) characterization of the indication revealed an approximate 60 degree circumferential flaw located 3/8" upstream of the pipe to flange weld, with no wall thinning. The indication was located in the Heat Affected Zone of the flange-to-housing weld, relatively small and tight, and exhibited slightly jagged characteristics. Based on the flaw characteristics the indication appeared to be IGSCC. Weld Overlay was the chosen repair method.

- In 2017, Fitzpatrick Unit 1 identified a rejectable indication on the RHR low pressure coolant injection loop. A full structural weld overlay was implemented using material that is IGSCC 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 isn't specifically applicable to HNP as all materials have been replaced for Category A welds, information for dissimilar metal (DM) welds at similar locations to Fitzpatrick's welds, like where the RHR system ties into the Recirc system, were reviewed to verify that they had been replaced with non-IGSCC susceptible materials and stress improvement applied during replacement in 1984.

  Per the resolution of a technical evaluation assigned to Site Engineering, it was determined that this OE is applicable to HNP as similar piping at HNP is also 304 SS. Indications from Susquehanna lead one to believe that OD corrosion may be a contributor for cracking as well. As a result, HNP has given instructions to under vessel personnel to look for material on these lines/flanges. Additionally, HNP planned a second pressure test walkdown during the RPV leakage test. These two actions gave Hatch a good indication of the susceptibility to this issue.

In addition, it was concluded that if this leakage were to be occurring, indication would be seen at the drywell floor drains, and those samples would be indicative of reactor coolant. Further, recent RPV pressure tests have shown no leakage in this area. No detailed surface or volumetric exams were performed on these areas at that time since large amounts of dose to workers would be incurred for what would likely be partial examinations.

- In 2023, World Association of Nuclear Operators (WANO) SER 2023-02 was issued with the action to evaluate. The SER details a series of unexpected defects that were detected near welds in safety injection piping attached to the reactor coolant system. The defects were stress corrosion cracks that developed on the inner wall of SR austenitic stainless-steel pipes that were considered immune to such degradation phenomenon; as such, preventive maintenance checks and inspection techniques were not specifically designed to detect such defects. The action required of the SER are that all members were expected to review the WANO SER closely in light of their own plant procedures, policies and practices to determine how this OE can be applied at their plants to further improve safety.

  HNP responded to the SER by determining that the issue present in the SER is only applicable to PWRs, but in order to drive the station towards excellence integrated IGSCC specific ultrasonic testing into the next and future planned volumetric inspections of the locations of interest described in the SER.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation and the relevant OE item is as follows:

- Documentation of Previously Issued Severity Level III Violation – Violation of 10 CFR 50.9

  During an NRC Inservice Inspection conducted on February 22 – June 30, 2016, a violation of NRC requirements was identified based on HNP’s failure to provide information that was complete and accurate in all material respects. This information was material to the NRC since it was used by the NRC to approve the reliefs/proposed alternatives. HNP requested relief from ASME Code requirements (as clarified in NUREG-0313 Revision 2 and GL 88-01) on the basis that weld overlay 1B31-1RC-12BR-E-5 was of standard overlay design, when in fact, the overlay was a “design” overlay (leak barrier). Also, HNP requested deferral of the required UT exam for the 1B31-1RC-12BR-E-5 weld overlay, based in part that it was a full-structural weld overlay when in fact, the overlay was a leakage barrier overlay.

  This issue was the result of mismanagement of information by HNP personnel which resulted in losing track of the type of configuration that had been implemented to deal with IGSCC in 1988. Upon discovery of the degraded condition during the Spring 2016 refueling outage, HNP took corrective actions to repair this condition. HNP also determined the configuration was reportable and submitted Licensee Event Report 2016003, “Reactor Coolant System Piping Has Unacceptable Weld Indication Discovered During Refueling Outage.”

The NRC concluded that information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence and the date when full compliance was achieved and adequately addressed on the docket in Inspection Report 2016-010 dated August 11, 2016.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The BWR Stress Corrosion Cracking 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 periodically evaluated.

Conclusion

The BWR Stress Corrosion Cracking 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.2.3.6 BWR Penetrations

Program Description

The BWR Penetrations AMP is an existing AMP that is part of the ASME Section XI Inservice Inspection Program that manages cracking due to cyclic loading, SCC and IGSCC for BWR vessel penetrations and nozzles. The in-scope components for this AMP includes vessel instrumentation penetrations, housing stub tube and incore-monitoring housing (ICMH) penetrations, and standby liquid control (SBLC) nozzles/Core ΔP nozzles. The AMP includes inspection and flaw evaluation in conformance with the guidelines of NRC-approved BWRVIP Topical Reports BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A. The AMP uses non-destructive testing, inspections, water chemistry control, and repairs when required. This AMP monitors the effects of SCC, IGSCC, and cyclic loading on the intended function of the component by detection and sizing of cracks by in-service inspection in accordance with the guidelines of approved BWRVIP-49-A, BWRVIP-47-A or BWRVIP-27-A, as well as the requirements of ASME Code, Section XI, Table IWB-2500-1. Inspections are scheduled and performed in accordance with the approved ASME Section XI Edition / Addenda as outlined in the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD AMP. BWR water chemistry is controlled per the Water Chemistry AMP and BWRVIP Mitigation Program.

Volumetric, surface and visual examinations and leakage test provide adequate assurance that any flaw(s) that might have propagated through the subject welds are identified and repaired prior to returning the plant to power operation. Identified flaws are repaired or replaced, in accordance with the Hatch Vessel and Internals Program – Reactor Vessel Internals Bases Document including guidelines provided in BWRVIP-58-A, BWRVIP-57-A, BWRVIP-55-A and BWRVIP-53-A.

NUREG-2191 Consistency

The 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

HNP evaluates industry OE items for applicability per site procedure and takes appropriate corrective actions. A search of the Institute of Nuclear Power Operations (INPO) OE database was performed and Industry OE relevant to this AMP are as follows:

- In May 2009, a planar flaw was found in a reactor vessel instrument nozzle safe end during an ultrasonic testing of instrument nozzle safe ends. The flaw was approximately 0.20" in the through wall dimension and the safe end wall thickness was measured to be approximately 0.25". A full structural weld overlay repair was performed before startup from the refueling outage. The cause of this event was determined to be excessive residual stress introduced to the safe end ID during fabrication. This high residual stress, coupled with the high oxidant content of the water in this area of the vessel and the weld heat affect zone microstructure form an 80% through wall stress corrosion flaw approximately 0.25" from the centerline of the weld.

  No Hatch condition report was identified that evaluated this specific industry OE. However, the in-scope components for this AMP, instrumentation penetrations, CRD housing and ICMH penetrations, and standby liquid control nozzles/core nozzles are periodically examined using volumetric, surface and visual nondestructive examination methods to detect discontinuities, flaws, and defects.

- In October 2020, an active leak at a two-inch instrumentation nozzle was identified by a visual examination during the RPV pressure boundary system leakage test. The root cause of the leak was determined to be IGSCC at the J-groove weld which was made of Alloy 182, which is known to be susceptible to IGSCC.

  No Hatch condition report was identified that evaluated this specific industry OE. However, the in-scope components for this AMP, instrumentation penetrations, CRD housing and ICMH penetrations, and standby liquid control nozzles/core nozzles are periodically examined using volumetric, surface and visual nondestructive examination methods to detect discontinuities, flaws, and defects.

- In March 2023, a flaw was identified in a dissimilar metal weld on a reactor penetration, nozzle to safe end weld. The results indicate a defect present which was found to unacceptable under ASME Section X1, IWB-3600. During the previous Inservice Inspection, this penetration did not show signs of indication. The most likely cause of the flaw growth was determined to be caused by SCC due to residual stresses internal to the weld that was created by local repairs of the welds during original fabrication. The nozzle -safe end weld is also a dissimilar metal weld, between the carbon steel recirculation discharge nozzle and the stainless steel safe-end. The weld materials are Inconel alloys

182 and 82. The characteristics of these indications were determined to be typical of SCC located in Alloy 182 weld material.

No Hatch condition report was identified that evaluated this specific industry OE. However, the in-scope components for this AMP, instrumentation penetrations, CRD housing and ICMH penetrations, and standby liquid control nozzles/core nozzles are periodically examined using volumetric, surface and visual nondestructive examination methods to detect discontinuities, flaws, and defects.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. No conditions reports were identified relative to degradation of in-scope components due to the aging effect of crack initiation and growth.

Integrated Inspection Reports:

- Integrated Inspection reports, which document NRC inspections findings, were reviewed over the last five years (2019-2024). During this period, there were no findings considered non-cited violations (NCVs) that were identified by either the NRC that were related to this AMP.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The BWR Penetrations 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.2.3.7 BWR Vessel Internals

Program Description

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 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 RVI 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 HNP, 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 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 BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB-2500-1. However, HNP utilizes an NRC Approved Request for Alternative Implementation of the BWRVIP Program for Vessel Internals in lieu of the requirements of ASME Code, Section XI, due to the fact that the NRC found that the proposed alternative provided an acceptable level of quality and safety for the vessel internals components because the proposed alternate provides for equivalent or superior flaw detection and characterization with an examination frequency that is equivalent or more frequent than the ASME Code requirements. 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.

Core Shroud: The shroud is inspected and evaluated per the requirements of BWRVIP-76, Revision 1-A. BWRVIP-02, Revision 2-A provides guidelines for repair design criteria.

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 2-A. The repair design criteria in BWRVIP-16-A and BWRVIP-19-A would be used in preparing a repair plan for core spray system components that are internal to the reactor vessel.

Shroud Support: Inspections and evaluations are performed in accordance with BWRVIP-38. Repair design criteria in BWRVIP-52-A would be used in preparing a repair plan for the shroud support. HNP Unit 2 has a shroud support design that is unique in the BWR Fleet. The 8.8-inch thick low-alloy steel shroud support plate is welded to the shroud and attached to the low-alloy steel RPV wall with a low-alloy steel weld (H9) that is not susceptible to IGSCC. The H8 weld connecting the support plate to the shroud cylinder was structurally replaced with a shroud stabilizer modification and is therefore not required to be examined by BWRVIP documents.

Jet Pump Assembly: Inspections and evaluations are performed in accordance with BWRVIP-41, Revision 4 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: HNP RVIs 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-A. The repair design criteria in BWRVIP-50-A would be utilized in preparing a repair plan for the top guide. As a BWR/4, the requirement at HNP is to inspect 10 percent of the grid beam cells containing control rod drives/blades every 12 years with at least 5 percent to be performed within 6 years.

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: Inspections and evaluations for the steam dryer components are performed in accordance with BWRVIP-139, Revision 1-A. The repair design criteria in BWRVIP-181-A would be utilized in preparing a repair plan for the steam dryer.

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 Applicant Action Items listed in the NRC SERs for BWRVIP reports are addressed in Appendix C.

NUREG-2191 Consistency

The BWR Vessel Internals AMP, with enhancements, is consistent without exceptions to the 10 elements of NUREG-2191, Section XI.M9 “BWR Vessel Internals.”

Exceptions to NUREG-2191

None.

Enhancements

The BWR Vessel Internals AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	**Enhancement**
1 - Scope of Program	Add BWRVIP-19-A which provides guidelines for repair design criteria into the Vessel and Internals program and add to the Vessel and Internals Program – Reactor Vessel Internals Bases Document.
1 - Scope of Program	Add BWRVIP-315 which provides a review of how existing BWRVIP AMPs may be affected by operations beyond 60 years. The work in BWRVIP-315 may lead to future updates of existing BWRVIP guidance documents and future NRC reviews. The BWR Vessel Internals AMP acknowledges that the BWRVIP SLR guidance continues to develop, and will continue to implement the most recent NRC-approved versions of the BWRVIP guidance. To implement the guidance in BWRVIP-315, the following BWRVIP guidance documents require revision (as shown in BWRVIP-315) in order to address operation beyond 60 years. The BWR Vessel Internals AMP therefore also requires enhancement to implement these required BWRVIP revisions: • BWRVIP-26-A, “BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines” • BWRVIP-41-R4-A, “BWR Vessel and Internals Project, BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines” • BWRVIP-47-A, “BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines” • BWRVIP-76, R1-A, “BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines” • BWRVIP-183-A, “BWR Vessel and Internals Project, Top Guide Beam Inspection and Flaw Evaluation Guidelines”

1 - Scope of Program	A revision to BWRVIP-315-A, “Reactor Internals Aging Management Evaluation for Extended Operations” was published in April 2024 (ML24191A266). A proprietary and NP version was forwarded to NRC on 6/18/24 (ML24191A244). HNP has initiated a tracking item for implementing this new version of BWRVIP-315 as well as approved revisions to the above BWRVIP guidance documents into the program.
3 - Parameters Monitored/Inspected	Add BWRVIP-234 to the Vessel and Internals program and add to the Vessel and Internals Program – Reactor Vessel Internals Bases Document.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

There is industry OE documentation of cracking in both the circumferential and axial core shroud welds, and in shroud supports. Extensive cracking of circumferential core shroud welds has been documented in NRC GL 94-03. Cracking has affected shrouds fabricated from Type 304 and Type 304L SS, which is generally considered to be more resistant to SCC. Weld regions are most susceptible to SCC, although it is not clear whether this is due to sensitization, impurities associated with the welds, or the high residual stresses in the weld regions. This industry experience is reviewed in NRC GL 94-03 and NUREG-1544.
The HNP response to NRC GL 94-03 was to implement the repair process developed by General Electric (GE) that involved installing four low-tension tie rod assemblies in the annular space between the core shroud and the RPV wall. The upper portions of the tie rods attached directly to the top of the shroud, and the bottom portions attached to existing gusset plates. Lateral stabilizers were provided in the middle and at both ends of the tie rod assemblies to accommodate design basis accidents (DBAs) and seismic loads. The HNP repair process structurally replaced all 304 SS circumferential shroud welds (welds H1 down through H7). That is, all these welds were assumed to have failed 360° through-wall with no credit taken for remaining weld ligament integrity. The shroud support ring to shroud support plate weld (H8) is a non-creviced, Inconel Alloy 600 weld with post-weld heat treatment applied during the manufacturing of the RPV and is less susceptible to IGSCC than the 304 SS welds. However, this weld was also structurally replaced with the repair. The design met the generic core shroud repair design criteria developed by the BWRVIP and submitted to the NRC staff for review by letter dated August 18,1994. The Unit 1 core shroud repair was performed in the Fall 1994 Refueling Outage, with the Unit 2 core shroud repair performed in the Fall 1995 Refueling Outage.

Extensive cracking in vertical core shroud welds has been documented in NRC IN 97-17. The HNP evaluation of IN 97-17 determined that NHP did not require additional core shroud weld inspections. In the response to GL 94-03, HNP had previously stated that inspections of welds and permanent shroud repair would be performed using BWRVIP-07, “BWR Vessel and Internals Project: Guidelines for Reinspection of BWR Core Shrouds” (Now superseded by BWRVIP-76-A, “BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines").

A 360-degree crack at a weld in the lower region of the core shroud in two BWRs were observed during visual inspections as discussed in NRC IN 94-42. The HNP evaluation of IN 94-42 stated that Unit 2 shroud inspection activities were performed during the 1994 Spring Refueling Outage and Unit 1 core shroud repair activities were scheduled to be performed during the 1994 Fall Refueling Outage. The Unit 2 shroud weld inspection identified UT indications for welds H1, H2, H3, and H4. The visual inspection of welds H5, H6 A&B, and H7 revealed no indications. An evaluation determined the welds were acceptable for continued operation over the next two cycles of operation. HNP opted to forgo the inspection of Unit 1 core shroud welds during the 1994 Unit 1 fall outage and instead proceed with GE's recommendation for shroud repair. As a result, GE-designed shroud tie rod repairs (see the GL 94-03 discussion above) were implemented in 1994 for Unit 1 to structurally replace all horizontal welds from H1 to H8. The same design was implemented on the Unit 2 core shroud in the Fall 1995 Refueling Outage. Following these repairs, HNP discovered Unit 1 cracking on the tie rod repair assembly and implemented a new tie rod repair design on Unit 1 in 2008 and Unit 2 in 2009 to address the cracking.

Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) had been observed in the industry on shroud support access hole covers that are made from Alloy 600. The HNP evaluation of IN 92-57 stated that both units had Inconel Alloy 600 access hole covers. The Unit 1 access hole covers had been UT inspected for circumferential cracking during the Fall 1991 Outage and found to be acceptable. The Unit 2 access hole covers were scheduled to be UT inspected for radial and circumferential cracking pending successful demonstration of a UT technique for radial crack detection by GE. Subsequently, the Unit 1 and Unit 2 access hole covers were replaced with a GE permanent repair design during the Spring 1993 Refueling Outage and Spring 1994 Refueling Outage, respectively.

Instances of cracking in core spray spargers have been reviewed in NRC IEB 80-13, and cracking in a core spray pipe has been reviewed in BWRVIP-18, Revision 1-A. The HNP response to IEB 80-13 stated that a visual inspection of HNP Unit 2 core spray spargers and associated piping was completed using remote underwater television cameras for the examination. No cracking of the core spray spargers or the segment of piping between the inlet nozzle and the vessel shroud was identified.

Cracking of the core plate has not been reported in the industry, but the creviced regions beneath the plate are difficult to inspect. BWRVIP-06, Revision 1-A and BWRVIP-25, Revision 1-A address the safety significance and inspection requirements for the core plate assembly. Inspection of core plate bolts is only required for plants without retaining wedges. Since HNP has retaining wedges installed, inspection of core plate bolts is not required. At HNP, only inspection of the retaining wedges is required.

NRC IN 95-17 discussed cracking in top guides of domestic and overseas BWRs. Related industry experience in other components was reviewed in NRC GL 94-03 and NUREG-1544. Cracking has also been observed in the top guide of a Swedish BWR. More recently, cracking was observed at the top guide grid to top guide rim cross-beam connection at a U.S. plant. The cause was attributed to IGSCC related to fabrication. The HNP evaluation of IN 95-17 stated that even though there are some differences, the HNP Unit 1 and Unit 2 top guide and core plate configurations were considered to be susceptible to the same type of cracking seen at the German BWR. The HNP weld joint configurations and locations are similar to those described, except that the core plate rim weld is full penetration at HNP vs. partial penetration at the German BWR. A full penetration weld would be expected to have higher weld residual stresses due to having more weld passes, which would result in higher weld shrinkage.

On January 3, 1995, the BWRVIP reported to the NRC the GE evaluation of the safety significance of this cracking event as it pertains to domestic BWRs. The BWRVIP used this information to incorporate appropriate core plate and top guide inspection and, if needed, evaluation/repair guidelines the overall vessel and internals program. A BWRVIP report for all internals, discussing IGSCC susceptibility ranking, safety consequences, inspection scopes and methodologies, flow evaluation, repair strategies, and mitigation of degradation was issued in the latter half of 1995. Upon receipt of the report, HNP determined the report recommendations would not enhance the HNP inspections of the top guides and core plates. The Unit 1 top guide had no wedges installed and the load path had been confirmed by GE to be through the aligner pins and associated brackets. GE analysis also confirmed that the top guide hold-downs are not required to perform a safety function, so they are not required to be inspected. The top guide aligner pin hardware had been included in the in-vessel visual inspection scope for the Unit 1 Spring 1996 Refueling Outage. An enhanced VT-1 inspection would be performed using the inspection methods recommended by the BWRVIP. The repair involved the installation of eight wedges between the top guide rim and the shroud wall, which also eliminated the need for any future inspections to meet the GE recommendations. The Unit 2 top guide had seismic wedges installed during construction and did not require any inspections to meet the GE inspection recommendations. The core plate for both HNP units had wedges installed as part of the shroud stabilizer modification and did not require any inspections to meet the GE inspection recommendations. Unit 1 aligner pin hardware and brackets were inspected and were found satisfactory. The Unit 2 aligner pin hardware and associated brackets were not inspected based on the GE recommendation that BWRs with top guide and core plate wedges did not need aligner pin hardware and bracket inspection.

Instances of cracking have occurred in the industry of a 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 was intergranular and has been observed in dry tubes without apparent sensitization, suggesting that IASCC may also play a role in the cracking. The HNP response to IEB 80-07 stated that visual examinations by remote underwater television cameras of the Unit 2 jet pump structures, hold-downs, hold-down beam assemblies, and wedge and restrainer assemblies revealed no abnormal wear, stress, or failed welds. Ultrasonic examinations were also conducted on the jet pump hold-down beams at the mid-length ligament areas bounding the beam bolt. It was determined that no cracking existed at those locations. Visual and ultrasonic inspections of Hatch Unit 1 jet pump components were scheduled for examination during the Winter 1981 Refueling Outage.

Two control rod drive mechanism (CRDM) lead screw male couplings were fractured in a pressurized water reactor (PWR) designed by Babcock & Wilcox, at Oconee Nuclear Station, Unit 3. The fracture was due to thermal embrittlement of 17-4 PH material (NRC IN 2007-02). While this occurred at a PWR, it also needs to be considered at BWRs. The HNP evaluation of IN 2007-02 was closed with no further action since HNP has a different coupling assembly design for the CRDM mechanism. Thermal aging of susceptible material is evaluated at HNP.

IASCC was observed in the industry at the core shroud beltline region and IGSCC was observed in core shroud tie rod upper supports made of X-750 alloy (BWRVIP-76-A). IGSCC in the X-750 alloy materials of a tie rod coupling and jet pump hold-down beam was observed in a domestic plant. An HNP Technical Evaluation was performed to evaluate design-related repairs to the Unit 1 and Unit 2 reactor internals made with X-750 alloy and to determine their design stress ratio. If the stress ratio was greater than 0.70 for non-threaded components or greater than 0.78 for threaded components, the component was considered highly-stressed and further evaluation was to be performed using BWRVIP letter 2011-011, “Guidance for

Evaluating Repair Hardware with X-750 components" as guidance. The technical evaluation determined that all X-750 repairs at HNP except for the Unit 1 shroud tie rod torsion arm bolts complied with the stress ratio requirements contained within BWRVIP letter 2011-011. The torsion arm bolts were evaluated as acceptable per a GEH evaluation and are inspected on a more frequent basis (every 6 years).

Plant Specific Operating Experience

A review of in-vessel visual inspection (IVVI) reports was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

The in-vessel visual inspection of RPV internal components during the Unit 1 Spring 2014 Refueling Outage identified the following:

1. Six relevant indications were found in the end plate base material of the steam dryer, beginning in the heat affected zone (HAZ) of the steam dryer vertical partition plate (VP) 3/2-4 weld. These weld indications were reported initially in 1987 with no discernible changes noted in 1999 or 2014. They were accepted as-is, with evaluations done in 1987, 1999 and 2014 all leading to the same conclusion that these cracks were due to cold work. With no evidence of an active fatigue mechanism, and the fact that the driving force for crack propagation due to IGSCC is reduced as the crack grows, corrective action was not warranted because these indications remained stable.
2. Several shroud head bolts (SHBs) were noted with various degrees of new wear observed on the indexing pin and window areas of the bolts. Disposition: With no significant wear noted, immediate actions were not required. HNP had accelerated visual examination frequency of non-creviced bolts from eight to six years based on HNP-specific experience and NSSS vendor guidance. No change to the inspection strategy was considered to be warranted.
3. On the 180° top guide alignment pin, a crack-like indication was observed along the surface of the washer which was welded between the alignment pin and its securing bolt. An evaluation determined that since the welds provided residual stress and the washer was fabricated out of 304 stainless steel, IGSCC was the most probable cracking mechanism. The top guide alignment pin was considered acceptable as-is for continued operation.
4. New crack-like indications not associated with a horizontal or vertical weld were found on the core shroud between horizontal welds H3 and H4 on the inner diameter (ID) surfaces of the shroud. Disposition: These indications were most likely a result of surface cold work (grinding). Grinding marks could be seen in the vicinity of all the indications. An evaluation determined that the indications were bounded structurally by larger flaws elsewhere in the shroud.
5. Crack-like indications were reported on the shroud outside diameter (OD) surfaces along both horizontal welds H4 and H5. Disposition: The indications were evaluated and had no operability impact. Both units at HNP have tie-rods installed which structurally replace the horizontal welds in the shroud. The calculation done for the evaluation determined the largest flaw was bounded by an acceptable flaw.
6. Crack-like indications were discovered in the core shroud from the ID and OD surfaces at the H4/V4 weld intersection. Disposition: Flaw evaluations demonstrated the acceptability of the indications. Calculations confirmed that the bounding flaw remained on the V6 weld.
7. The examination performed on the 176° top guide hold-down assembly revealed two indications on the clockwise and counterclockwise with minor wear on the ends of the

pin which had not been previously reported. Disposition: No corrective action was considered necessary at that time. It was expected that the wear would continue at a slow rate.

8. Several indications were found along horizontal weld H3 and vertical welds V5 and V6 during an VT-3 exam of the shroud ID shroud surfaces between welds H1 and H5. Disposition: An evaluation concluded that flaws on the shroud were structurally acceptable and the shroud was capable of performing its design function for at least 10 additional years.
9. Crack-like indications were discovered on the core shroud ID and OD surfaces at the H5 and V8 weld intersection. Disposition: Flaw evaluations demonstrated the acceptability of all indications and were used to show that they did not pose a functionality or operability concern. The circumferential shroud welds, including H5, were structurally replaced by the shroud tie rods and therefore, circumferential flaws associated with these welds are not a concern structurally. Calculations evaluated the V5 and V6 flaws, and shroud flaws perpendicular to welds and confirmed that the bounding flaw remained the largest flaw on the V6 weld. Since the bounding V6 flaw was structurally acceptable, it followed that these indications at the H5/V8 weld intersection were acceptable.
10. Numerous indications were reported as a result of volumetric examination of core shroud vertical welds and weld intersections. Comparing the results of V5 and V6 welds from 2004 to 2014 shows that only one flaw along V5 and V6 has grown in length. However, two of the indications had grown in the depth direction, including a flaw along V6 that had grown through-wall. Additionally, four indications were found within the base metal of the core shroud, one of these indications was examined via UT. Disposition: Calculations confirmed that the reported indications did not pose a functionality or operability concern. As multiple flaws were found to be through-wall in depth, HNP was required to account for leakage emanating from these flaws. Leakage calculations demonstrated adequate margin existed in the LOCA analysis to cover the calculated leakage for the through-wall indications identified.

The in-vessel visual inspection of RPV internal components during the Unit 1 Spring 2016 Refueling Outage identified the following:

1. Inspection of the steam dryer tie bars 7 and 8 revealed crack-like indications on the 0° and 180° sides of the welds attaching tie bars 7 and 8 to the steam dryer divider plate between banks 2 and 3. No other tie bar indications were noted. Disposition: An evaluation of the steam dryer tie bar 7 and 8 indications and concluded that there were no structural or loose part concerns with the condition of the tie bar 7 and 8 divider plate welds, there was no safety concern for continued operation with the reported indications at tie bars 7 and 8, and that the steam dryer was acceptable for one cycle of operation.
2. Inspections performed on the steam dryer upper and lower guides at the 0° and 180° location revealed gouge marks on the inside of the bracket where the guide rod travels along the 0° and 180° guides. The upper and lower guides at 0° had several areas with gouges and rolled metal with possible loss of material. Review of Unit 1 2006 Refueling Outage and Unit 1 Spring 2008 Refueling Outage video showed that these were pre-existing conditions, with several of these indications reported as early as 1991. There was no discernible change in the gouge marks on the 180° lower guide when compared to the Unit 1 2006 Refueling Outage, but rolled metal was also found on the upper guide at 180°. Disposition: Because there had been no change since the 2006/2008 time frame and these indications did not affect the structural integrity of the steam dryer or had the potential to create loose parts, no further action was required.
3. During the visual examination of all Unit 1 jet pump adjusting set screw gaps, several

gaps were identified between the set screws and mixers. In addition, all 20 jet pump restraining bracket wedges were examined for wear of the top and bottom of the wedge at the wedge rod. A slight amount of wear, estimated at less than one percent of the rod diameter, was noted from contact with the bottom of the wedge at JP 06. Disposition: The as-left condition of the restrainer bracket set screw gaps at JP 05 and JP 15 were determined to be acceptable for continued service. The remaining jet pump restrainer bracket set screw gaps were acceptable in their as-found condition. The wedge rod wear documented at JP 06 was minor and also less than the BWRVIP acceptance criteria of maximum 10 percent rod wear.

4. Several core shroud indications on the OD and ID surfaces were observed. Previously noted OD-initiated flaws dating from 1997 were reinspected. These flaws were typical IGSCC flaws running parallel to welds V5 and V6 within the HAZ. Exams were also performed on the shroud ID and OD along the H4 weld in locations of five vacated fuel cells in order to identify additional off-axis or through-wall shroud cracking. One or more flaws were noted in each cell except for one. On the shroud ID surface, off-axis or "transverse" flaws were reported. On the OD surface, two short indications aligned with two indications from the ID and were presumed to have grown through-wall. Disposition: Base metal flaws were bounded by existing flaw evaluations and a calculation, and therefore were acceptable for continued service. The linear flaws were bounded by existing flaw evaluations and a calculation. The transverse flaw was not a concern due to existing tie rod repairs for horizontally oriented flaws. H4 off-axis flaws were bounded by existing flaw evaluations and a calculation, and therefore were acceptable for continued service. The flaws presumed to be through-wall at this location were also bounded by the existing leakage evaluation.

The in-vessel visual inspection of RPV internal components during the Unit 1 Spring 2018 Refueling Outage identified the following:

1. Inspections of the 086° and 176° top guide hold-down assemblies resulted in: (1) a previously undocumented indication (from the Spring 2010 Refueling Outage) being noted on the 086° top guide hold-down assembly and (2) no apparent change in the previously identified (during the Spring 2014 Refueling Outage) indications on the 176° top guide hold-down assembly. Disposition: The indications on the 086° and 176° top guide hold-down assemblies were characterized as apparent wear that was shared between the pin and slot in which the pin was located. The as-found condition on the 086° and 176° top guide hold-down assemblies were considered acceptable for continued operation.
2. Visual inspections performed on the jet pump restrainer bracket adjusting set screw locations on JP 05, JP 10, and JP 15 revealed: (1) gaps between the adjusting set screws and jet pump mixer on JP 05 shroud and vessel sides, (2) gaps between the adjusting set screws and jet pump mixer on JP 10 shroud and vessel sides, and (3) no gaps between the adjusting set screws and jet pump mixer on JP 15 shroud and vessel sides. Disposition: The adjusting set screw gaps on JP 05 and JP 10 were bounded by an evaluation performed for HNP. Based on the as-found condition of the jet pump restrainer bracket adjusting set screw locations on JP 05, JP 10, and JP 15, they were considered acceptable for continued operation.
3. Six previously identified and two new indications on the end plate base material of the steam dryer were observed beginning in the HAZ of the steam dryer vertical partition plate (VP) 3/2-4 weld. Disposition: The inspection results showed no apparent changes to the six indications previously observed during the Unit 1 Spring 2014 Refueling Outage. These six indications were initially identified in 1987 and reinspected in 1999

and 2014. The two new indications were located in the same area (end plate base material in the HAZ of the steam dryer VP 3/2-4 weld) and situated between two previously identified sets of indications. The as-found condition on the steam dryer VP 3/2-4 weld was considered acceptable for continued operation.

4. Two indications were found on the top guide beam connection. Based on these findings, additional inspections were performed that resulted in 13 relevant indications at the collar and bottom support ring. Disposition: A structural analysis was performed on the top guide beam connection condition. Based on the evaluation, the top guide and its beam connections would perform their SR function in the as-found condition and was considered acceptable for continued operation. Additionally, specific guidance released by the BWRVIP was incorporated into future inspection frequencies for the top guide beam connection collars.

The in-vessel visual inspection of RPV internal components during the Unit 1 Spring 2020 Refueling Outage identified the following:

1. JP 14 inspections resulted in the identification of previously undocumented wear patterns into the jet pump inlet mixer (“belly band”) from both the vessel side and shroud-side jet pump restrainer bracket adjusting set screws. The new indications (when compared to the 2016 Spring Refueling Outage data) were at the same location of the jet pump inlet mixer where the vessel and shroud-side jet pump restrainer bracket adjusting set screws engage the “belly band” and showed no apparent changes to the wear patterns. Since the observed indications on the jet pump inlet mixer would not prevent the jet pump performing its intended function, the as-found condition on the “belly band” was deemed acceptable for continued operation.
2. Ultrasonic Examination of the shroud revealed small through-wall indications at the H4 weld. These indications were comparable to the 2014 indications with some exceptions. These through-wall indications were justified for one additional cycle of operation using conservative assumptions but would however contribute to overall leakage out of the shroud during a LOCA. Preliminary analysis showed more than adequate margin existed to accommodate the leakage. All reported shroud indications from the Unit 1 Spring 2020 Refueling Outage were deemed acceptable for continued operation for a minimum of one additional cycle.
3. Non-creviced moisture separator shroud head bolt inspections resulted in non-relevant indications on six SHBs, no discernible change in previously identified pin and/or window wear on eight SHBs, new wear being identified on the pin and window for two SHBs, new wear being identified on the pin for one SHB, a crack being identified on the sleeve base for SHB 31, identification of missing pin material on SHB 35, and identification of no tee-bolt contact witness marks on SHB 35. SHBs 31 and 35 were replaced (like for like – non-creviced). Since the observed wear indications would not prevent the moisture separator SHBs from performing their intended function, the as-found condition on the remaining SHBs were deemed acceptable for continued operation.
4. The JP 14 type 3 hold-down beam was found loose during cleaning activities. All other JP group 2 hold-down beams were checked for looseness with none found. To determine the extent of condition, Unit 2 JP group 2 hold-down beams were scheduled to be checked for loose clamps during the Unit 2 Spring 2021 Refueling Outage.

The in-vessel visual inspection of RPV internal components during the Unit 1 Spring 2022 Refueling Outage identified the following:

1. Core shroud visual exams were performed from both the interior and exterior shroud

surfaces. Results from these shroud inspections included: (a) one lane with five axially oriented flaws; (b) one lane with four flaws in the vicinity of a weld intersection; (c) one lane with two flawed areas outside of weld HAZs; (d) two axially oriented indications at one vertical weld and one axially oriented indication at another weld. Disposition: An evaluation calculated the maximum allowable flaw length and confirmed a 10-year interval for reinspection to be structurally acceptable. However, fluence projections for the Unit 2 Shroud indicated that several welds would exceed fluence thresholds requiring re-evaluation during a future outage.

2. Indications were reported on the 146° and 214° steam dryer seismic brackets. A further relevant linear indication was noted not to have changed from the 2007 inspection on the 146° seismic bracket. An indication reported on the 214° bracket was determined to have been non-relevant surface staining with the aid of better lighting and viewing angles used during the Unit 2 Spring 2015 Refueling Outage. Disposition: All four seismic brackets were discovered to have indications in 2005 and were reinspected in 2007 and 2009 to monitor for changes. The linear indication noted on the 146° seismic bracket appeared not to have changed since at least 1998. The evaluation from 1998 which determined this indication was acceptable for continued service still applied.
3. Seven jet pump set screw gaps were found. All but one of the gaps noted occurred on the “A” recirc loop side of the vessel. Disposition: The documented set screw gaps were within the acceptance criteria and therefore were determined acceptable for continued operation. All set screw gaps, wedges, and wedge rods were inspected with acceptable results.

The in-vessel visual inspection of RPV internal components during the Unit 2 Spring 2017 Refueling Outage identified the following:

1. During the examination of the top guide hold-down at the 86° azimuth, a new relevant indication was observed in the shroud base material in the weld HAZ of the attachment weld between the bracket and the shroud on the 90° side of the bracket. Disposition: A qualitative evaluation of the top guide hold-down bracket condition determined that no mitigating action was needed aside from regular inspections.
2. Visual inspections on the SHBs noted that several had varying degrees of wear on the indexing pin and window areas. The SHBs that had additional wear (not previously identified) only had minor instances of increased wear. Disposition: The wear on the SHBs was minor; therefore, immediate actions were not required. The SHBs would continue to be monitored as indexing pin and window wear had been a common occurrence on both units.
3. VT-3 inspections of the guide rod and the guide rod brackets found an indication on the 0° vertical guide rod cap which was documented as smeared metal. Disposition: The damage on the guide rod cap was minimal; therefore, no immediate actions were required. The smeared metal on the guide rod cap was stable and was not a foreign material concern. The condition of the guide rod and guide rod brackets had been determined acceptable for continued operation.

The in-vessel visual inspection of RPV internal components during the Unit 2 Spring 2019 Refueling Outage identified the following:

1. VT-3 examinations performed on the shroud ID surface revealed a newly discovered relevant indication on the lower plate on the top guide rim. Disposition: Continued operation with this indication in place was acceptable because the as-found indication did not impact the ability of the top guide and its beam connections to perform their

functions. The most likely cause was IGSCC, based on crack appearance and fabrication methods and was therefore not expected to propagate beyond the pin location toward the rim.

2. Inspections were performed on core spray sparger brackets 60° mid, 240° mid, 240° lower, 330° mid and the 330° lower (after cleaning via hydrolazing) to assess the condition of indications that were last inspected during the Unit 2 Spring 2015 Refueling Outage and the Unit 2 Spring 2017 Refueling Outage. When compared to the results of the Unit 2 Spring 2017 Refueling Outage inspection, no discernible change was noted on the previously identified locations. However, a new indication was noted on the 240° mid bracket. Disposition: The new indication on the 240° mid bracket was examined from a closer distance with a better camera module and this new indication was determined to be acceptable for continued operation.
3. UT exam on the shroud OD surfaces identified one new linear indication on vertical weld V9 and two new branches in Cell 42-07. Disposition: All the inspection results were still bounded by the Spring 2015 Refueling Outage shroud structural evaluation. EVT-1 was performed on the OD surface of the shroud and determined that none of the previously identified indications were through-wall. All reported shroud indications were considered acceptable for continued operation.

The in-vessel visual inspection of RPV internal components during the Unit 2 Spring 2021 Refueling Outage identified the following:

1. Visual inspections of the core spray system nozzles found machining burrs on three core spray sparger nozzles. Disposition: The video showed the nozzles were rolled edges from machining and confirmed that they historical in nature and appeared to be in place since construction. They were not service-induced, not foreign material, and were not characterized as an indication. The rolled edges were determined to not represent a risk to function of the core spray system.
2. During visual inspections performed on the top guide beams, three Unit 2 in-core monitor dry tubes were found to have relaxed in the top guide seating area. These were evaluated as acceptable, but an extent of condition for Unit 1 was added to the Unit 1 Spring 2022 Refueling Outage during top guide grid beam examinations. Fifteen dry tubes were looked at on Unit 1, and eight were found partially disengaged but acceptable to run for another cycle. Based on these inspections, dry tube replacements will begin in 2024 per the HNP strategy to replace the dry tubes prior to their 20-year service life.
3. Visual examinations performed on 12 core spray sparger brackets, core spray sparger nozzles, four feedwater sparger brackets end pins, two surveillance sample holders, and one top guide hold-down observed previously found relevant indications that had no change since their previous inspections.
4. Visual examinations were performed of the core shroud ID surface. Linear indications were observed in the area of the H4 and H5 welds. Indications in three cells exhibited no discernible change. One was noted to have new growth on one indication but determined to be acceptable.
5. Visual inspections of the core spray sparger brackets found surface anomalies in the HAZ of the shroud-to-bracket weld in the shroud-side base material on the brackets at the 120°, 150° and 267.5° locations. The inspection showed marks that were classified as surface anomalies vs. cracks. The anomalies were representative of indications found at other locations which had been evaluated as acceptable and as such these new anomalies were considered acceptable for continued operation.

The in-vessel visual inspection of RPV internal components during the Unit 2 Spring 2023

Refueling Outage identified the following:

1. Inspections were performed on the moisture separator at the 0° and 180° guide rod brackets to assess the condition of indications that were previously inspected during the Spring 2017 Refueling Outage. The previously inspected moisture separator guide rod brackets and moveable guide pins were deemed acceptable for continued operation.
2. Inspections of non-creviced moisture separator SHBs were determined to be acceptable.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The BWR Vessel Internals 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.2.3.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

Program Description

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is a new AMP that will determine the potential significance of thermal aging embrittlement of cast austenitic stainless steel (CASS) components and detect the effects of loss of fracture toughness due to thermal embrittlement of CASS pump casings. The scope of the program includes ASME Code Class 1 piping components constructed from CASS with service conditions above 250°C (482°F). Since the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP is a new AMP, a new governing procedure will be created.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP will include a screening methodology to determine component susceptibility to thermal embrittlement based on casting method, molybdenum content, and percent ferrite. The criteria is set forth in NUREG/CR–4513, Revision 2 with errata (March 2021), the potential significance of thermal aging embrittlement of CASS materials is determined in terms of casting method, molybdenum content, nickel content, and ferrite content. Based on the results of this screen, if any components are determined to be potentially susceptible to thermal embrittlement of CASS, aging management will be accomplished through either (1) qualified visual inspections, such as EVT-1 enhanced visual examination; (2) a qualified ultrasonic testing (UT) methodology; or (3) a component specific flaw tolerance evaluation in accordance with the ASME Code, Section XI.

Examination methods that meet the criteria of the ASME Code, Section XI, Appendix VIII are acceptable. Inspection schedules will be in accordance with ASME Code, Section XI, IWB-2400 or IWC-2400 per the Inservice Inspection program, as well as, reliable examination methods, and qualified inspection personnel will be identified to provide timely and reliable detection of cracks. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components for which thermal aging embrittlement is not significant. Flaws detected in CASS components will be evaluated in accordance with the applicable procedures of ASME Code, Section XI. This AMP 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. NUREG/CR–4513, Revision 2 with errata provides methods for predicting the fracture toughness of thermally aged CASS materials with delta ferrite content up to 40 percent.

For valve bodies, screening for significance of thermal aging embrittlement is not needed (and thus there are no aging management review items). For valve bodies greater than or equal to 4 inches nominal pipe size (NPS), the existing ASME Code, Section XI inspection requirements are adequate. ASME Code, Section XI, Subsection IWB requires only surface examination of valve bodies less than 4 inches NPS. For valve bodies less than 4 inches NPS, the adequacy of inservice inspection (ISI) according to ASME Code, Section XI has been demonstrated by an NRC-performed bounding integrity analysis (May 19, 2000 Grime's letter, NRC000213, License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components"). The reactor recirculation pumps do not have an original flaw tolerance evaluation as defined by implementing code case N-481. Therefore, the potential significance of thermal aging embrittlement of CASS materials will be determined based on the May 2000 Grimes' letter.

NUREG-2191 Consistency

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

Review of the last three LRA/SLRAs submitted with a discussion of CASS recirculation pump casings related to thermal 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 River Bend Station and not applicable per NUREG-1801. There is no relevant OE related to thermal embrittlement in River Bend's LRA.
- Monticello Nuclear Generating Plant SLRA: The Thermal Aging Embrittlement CASS program is credited for SLR at Monticello Nuclear Generating Plant and addresses applicable key elements (the "ten" elements") identified in NUREG 2191. There is no relevant OE to date related to thermal aging embrittlement.

This review of thermal embrittlement concerns at BWRs shows no industry-wide issue regarding recirculation pumps.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation.

Condition Reports from the past 10 years were reviewed and no instances of issues with the in-scope pump casings or covers or other CASS components were identified, nor any ISI inspections that require inspection of the internals of the pumps when disassembled.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel 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 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel AMP will be consistent without exception to NUREG-2191, Section XI.M12. The Thermal Embrittlement of Cast Austenitic Stainless Steel AMP will provide reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the CLB through the SPEO. The Thermal Embrittlement of Cast Austenitic Stainless Steel AMP will be implemented prior to the SPEO.

B.2.3.9 Flow-Accelerated Corrosion

Program Description

The Flow-Accelerated Corrosion AMP is an existing condition monitoring program that predicts, detects, and manages wall thinning caused by FAC. The FAC AMP is also used to inspect wall thinning due to erosion mechanisms, if present, that are not being managed by another program. The program is based on commitments made for an ongoing monitoring program in response to NRC GL 89-08 and relies on implementation of the EPRI guidelines in the Nuclear Safety Analysis Center NSAC-202L-R4 report about implementing an effective FAC program.

The FAC AMP includes:

1. Identifying all susceptible piping systems and components;
2. Developing FAC predictive models to reflect component geometries, materials, and operating parameters;
3. Performing analysis of FAC models and, with consideration of OE, selecting a sample of components for inspection;
4. Inspecting components;
5. Evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections;
6. Incorporating inspection data to refine FAC models.

The program includes the use of predictive analytical software that uses the implementation guidance of NSAC-202L-R4, which recommends inclusion of QA requirements, of which HNP applies the Plant Design Software Control procedural document to control the software. Any currently performed software QA activities (e.g., validation and verification, error reporting) for each software program used in the FAC program will continue, even though these activities are not required by the software QA classification.

This program will also manage wall thinning caused by mechanisms other than FAC in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms. Guidance in the FAC Program Implementation procedural document is used to monitor erosion mechanisms.

NUREG-2191 Consistency

The Flow Accelerated Corrosion AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section X.M17, "Flow Accelerated Corrosion."

Exceptions to NUREG-2191

None.

Enhancements

The Flow-Accelerated Corrosion AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
1 - Scope of Program 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.
1 - Scope of Program	Formalize a separate erosion susceptibility evaluation (ESE) that will include all components determined to be susceptible to wall loss due to erosion that are not being managed by another program, determined through OE and industry guidance.
5 - Monitoring & Trending	Revise or provide procedure(s) for measuring wall thickness due to erosion. Wall thickness should be trended to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements.
5 - Monitoring & 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 surveillance or pump starts/stops, then trending activities should consider the number or duration of these occurrences.
5 - Monitoring & Trending	Revise or provide procedure(s) to perform periodic wall thickness measurements of replacement components until the effectiveness of corrective actions have been confirmed.

6 - Acceptance Criteria	Revise or provide procedure(s) to provide guidance consistent with the erosion service life safety factor from EPRI 3002023786 for erosion mechanisms. Changes that recommend an increase in safety factor to 2.0 will be documented.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

- The NRC issued IN 2019-08 to inform addressees of recent OE in which FAC events resulted in reactor trips. The NRC expects that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems.

The events described and SNC's response to the events are as follows:

1. At Indian Point Energy Center, Unit 3 on September 18, 2018, while in Mode 1 at 100 percent reactor power, operators manually tripped the reactor and closed all main steam isolation valves in response to a steam leak on a 6-inch elbow located upstream of the 36C feedwater heater. The root cause was attributed to program engineers not using replacement history to identify FAC susceptibility, as components on this line had shown FAC related failure in the past. Corrective actions included replacing the failed component, revising the model to split the reheater drain branches into three separate runs with one run per heater, and revising procedures on scope expansion and system replacement history. SNC's response was that they have a strict adherence to procedural guidance to avoid such situations, emphasizing that inspection points are selected based on previously identified wear.

2. At Davis-Besse Nuclear Power Station on May 9, 2015, while in Mode 1 at 100 percent reactor power, field operators at Davis-Besse reported a steam leak on a 4-inch pipe in the moisture separator reheater system. After initiating a rapid shutdown, the operators manually tripped the reactor from approximately 30 percent power. The root cause was an incorrect data input caused the FAC software model to underestimate the predicted wear rate, so inspections were not performed to identify the wall thinning before failure. Additionally, corrective action from a comparable event in 2006 did not include a validation of all critical data inputs. Corrective actions from the more recent event included improvements in the fidelity of the data in the FAC software model. SNC's response was that they will improve upon the models wear predictions based off of information gathered during outages and identify where the software is currently not calibrated.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- A physical inspection of select FAC susceptible piping described as having FAC resistant materials was conducted in June of 2013 in support of a site LR activity for the FAC program. The following tasks were performed during the inspection: Created a list of replaced components from a historical review of the Hatch FAC program; Identified possible flow-accelerated corrosion/erosion mechanisms; Performed a follow-up inspection. Upon completion of the tasks the program was determined to be effective, and the components list was filed in SNC's database.

- In February of 2014, during the first performance of the FAC exams, a misinterpretation of a portion of the FAC non-destructive examination (NDE) procedure resulting in having to retest components to collect and record information. For future outages, a presentation and data packages were provided to all FAC NDE contractors prior to the outage ensuring no misinterpretation could occur.

- In March of 2015, a FAC component was an radiography testing (RT) point for the FAC program as documented in the HNP Spring 2015 Refueling Outage post outage report. However, the RT sample was unreadable because the pipe was too thick for the RT energy to penetrate enough to read. To determine if the component passed engineering evaluation, the upstream and downstream components were reinspected and found to be of acceptable values. Thus, given the information that the upstream and downstream components were acceptable and the fact that the component was too thick to read, it was determined that it also passed engineer evaluation.

- In April of 2017, the 12th Stage A and B feedwater heaters had a continuous venting system. This system has several restriction orifices of whose failure can cause FAC damage to the internal piping of the feedwater heaters. Upon initial inspection a regular inspection and replacement had been setup for these orifices to prevent excess damage to the feedwater heaters.

- During an outage in February of 2017, the condenser connection #58 failed FAC inspection. This connection is the downstream nozzle of the main condenser shell B. These were vendor supplied condenser nozzles that were not replaced with same schedule pipe or flow accelerated corrosion (FAC) resistant piping when upstream piping was replaced with chromium molybdenum steel. This piping condition caused damage in the nozzles resulting in air in-leakage into the condenser in one incident and weld overlay repairs in others. Both the leak and the overlays were caused by the assumption the condenser nozzles could not be replaced in a timely manner during outages. The plant has replaced the nozzles in question with the same schedule piping and FAC resistant material and now replaces nozzles as part of the pipe replacement strategy.

- During an outage in May of 2018, FAC was discovered on the outlet portion of a valve seat landing. This area was not a pressure retaining portion of the valve, so the valve was able to perform a full operating cycle with no issues. Replacement with a valve made of non-FAC susceptible material was performed in the following outage.

- While performing rounds in the Unit 2 turbine building in December of 2019, a leak was discovered at the top of the western most tenth stage heater. The leak was determined to be coming from the piping at the top of the heater, from the 90 degree elbow extraction steam piping going into the heater. The failure was determined to be caused by a FAC-related failure, leading edge effect. The elbow was replaced with non-FAC susceptible material in the following outage.

- During an outage in February of 2024, an elbow feeding the feedwater system had a measured thickness of a value below the critical thickness (T_{crit}) allowed for that component, which required immediate repair or replacement. Upon further investigation, it was discovered that a leak past the reactor feedwater pump minimum flow line valve caused the immediate downstream elbow to prematurely wear which caused the elbow to require repair. Additionally, the elbow in the opposite train had been monitored for wear and found to be not as severe. Therefore, to prevent any future additional wear the valves in both trains were replaced with a different style to reduce leak-by.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Flow-Accelerated Corrosion 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 periodically evaluated.

Conclusion

The 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

Program Description

The 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 compressed air or gas for which leakage is difficult to detect.

Applicable industry standards and guidance documents relevant to this AMP include NUREG-1339 (Reference 1.6.18), “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” EPRI Report 3002015824 (Reference 1.6.19), “Nuclear Maintenance Applications Center: Bolted Joint Fundamentals,” and EPRI Report 3002008061 (Reference 1.6.20), “Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolting Joints: Update of Report 1015337.”

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 3002015824 and EPRI Report 3002008061, along with additional recommendations from NUREG-1339; consideration of actual yield strength when procuring bolting material; lubricant selection; 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, or engineering evaluation.

These actions will preclude cracking, loss of preload, and loss of material.

The Bolting Integrity AMP provides visual inspection of pressure-retaining bolting per engineering walk downs. For closure bolting within the scope of the ASME Code, these inspections are supplemented by examinations performed under the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP (Section B.2.3.1). Inspections will be performed by personnel qualified in accordance with corporate procedures and programs to perform the specified task.

For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic walkdowns and inspections ensure timely identification of indications of cracking, loss of preload 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. Inspections not conducted in accordance with the ASME Code are conducted in accordance with site specific procedures that include inspection parameters for items such as lighting, distance, and offset which provide an adequate examination. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the CAP.

Submerged closure bolting in submerged locations or in piping systems containing compressed 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 19 bolt heads and threads per Unit 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 walk downs performed to demonstrate proper sump pump performance. For closure bolting on piping systems containing compressed 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
- Torque checks on components that are not normally pressurized (performed to ensure that bolting is not loose)

Indications of aging in pressure-retaining bolting for ASME Code Class 1, 2, and 3 components are evaluated in accordance with Section XI of the ASME Code. Non-ASME Code inspections follow acceptance criteria established in plant procedures and specifications. Leaking joints do not meet acceptance criteria.

Submerged bolting in the suppression pool is managed by the Torus Submerged Components Inspections AMP (B.2.4.2) and supplements the Bolting Integrity AMP.

The aging effects associated with the following types of bolting are not managed by the Bolting Integrity AMP:

- Closure bolting for heating, ventilation, and air conditioning systems is managed by the External Surfaces Monitoring of Mechanical Components AMP
- Reactor head closure studs are managed by the Reactor Head Closure Stud Bolting AMP
- Bolting internal to the reactor vessel is managed by BWR Vessel Internals AMP
- Bolts associated with splices, or electrical connections are managed by the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP
- Buried piping valves, fasteners, and tanks (loss of material aging effect only, all other aging effects for these bolts are managed by the Bolting Integrity AMP) are managed by Buried and Underground Piping and Tanks AMP

NUREG-2191 Consistency

The 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 Bolting Integrity AMP will be enhanced as follows, for alignment with NUREG 2191.

Element	Enhancement
2 - Preventive Actions 3 - Parameters Monitored/Inspected	Create a procurement document to ensure that the maximum yield strength of replacement or newly procured pressure-retaining bolting material will be limited to an actual yield strength less than 150 ksi.
2 - Preventive Actions	Update bolting procedure to ensure that lubricants containing molybdenum disulfide (MoS_2) and other lubricants containing sulfur will not be used on pressure-retaining closure bolting.

3 - Parameters Monitored/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 compressed 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 percent of the population (up to a maximum of 19 per Unit).
3 - Parameters Monitored/Inspected	Update passive component inspections procedure to ensure non-ASME Section XI high-strength closure bolting (with actual yield strengths greater than or equal to 150 ksi), and bolting for which yield strength is unknown but may be greater or equal to 150 ksi, will be monitored for surface and subsurface discontinuities indicative of cracking.
4 - Detection of Aging Effects	Update passive component inspections procedure to ensure that bolted joints in areas that are accessible during normal operation are visually inspected once per refueling cycle.
4 - Detection of Aging Effects	Update passive component inspections procedure to ensure that bolted joints that are not readily visible during plant operations and refueling outages will be visually 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	Update passive component inspections procedure to indicate that closure bolting greater than two inches 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, but may be greater than or equal to 150 ksi, will require volumetric examination in accordance to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1.

5 - Monitoring & Trending	Update procedures 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 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	Include the guidance for corrective action in response to joint leakage (i.e., sample expansion and additional inspections if inspection results do not meet acceptance criteria).

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

- Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading. Assessment of NRC GL 91-17 resulted in three procedural enhancements at HNP. 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. The above ERPI reports have been updated to EPRI reports 3002008061 and 30020015824.

- Degradation-related failures have occurred in downcomer tee-quencher bolting in boiling water reactors designed with drywells. The Priority Attention Required Morning Report - Region II, report describes discovery of failed high-strength alloy steel bolts. The resolution of the OE is discussed in the Torus Submerged Components Inspection AMP (B.2.4.2).

- 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. There are no known applications where high-temperature/high-pressure bolting are used at HNP; 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 HNP.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows.

- In February 2015, the ISI examination of the RPV support skirt discovered approximately one-third of the 60 bolts had greater than minor corrosion. The bolting was repaired, and the system remained operable.

- In February 2016, a leak was discovered between two flange faces on the low power range monitor system. The flange surface and the flange bolting had visible signs of rust. The flange materials and bolting were repaired or replaced, and the leakage was stopped.

- In February 2021, while performing a VT-1 examination of bolting associated with maintenance activities on a feedwater line isolation valve, HNP identified thread damaged to pressure boundary bolting. Unacceptable indications identified include tooling damaged, galling, nicks, and other thread damage. The examiner was unable to determine if the tread damage was in the zone of thread engagement of the bolting material. Engineering confirmed that all damage noted in the VT-1 inspection is within the cover, and inside of the nut contact area. All damage is to threads only, and will not affect torque on the bolts, or the thread engagement of the nuts. The only indication that is close to the nut area is on the stuffing box side, but with an 1/8-inch gasket, as well as another 1/8-inch washer, this brings the thread engagement area past the indication on the threads and to an acceptable area.

- During a pre-job brief in September 2021, the proper torquing methods and torque values for bolting were discussed because it was required for the work being performed. To promote nuclear safety culture, personnel were questioning during this pre-job brief which torque valves to use. The following training and guidelines were provided to the crew as training for this work. The following methods are used to determine torque values. They are listed in the order in which they should be used. In some cases, a combination of these methods may be required to obtain all necessary torque values.
    - Component Specific Procedure: Some component specific procedures used within the fleet give specific torque values for certain components. This is the preferable method for obtaining torque value.

    - Approved Vendor Manual/Print: The approved vendor manual and or prints may give certain torque values for the components requiring torque. This is the 2nd method for obtaining torque value.

    - Torque Tables and Instruction Contained in the Torque Procedure: The torque procedure contains applicable torque tables for torque of fasteners based on fastener type, pressure boundary applications, electrical components, etc., as well as cases in which hand tightening is used. This is the 3rd method for obtaining torque value.

    - Engineer Calculated Torque: In certain cases, torque values will have to be calculated. This will be done by the system or maintenance engineering staff using the calculation form found in the torque procedure.

- In October of 2021, an NRC resident identified a concern with the bolting on a flange of the temporary diesel fire pump. The NRC identified several flange bolts that are not flush or protruding from their respective nuts. HNP found the bolting on the temporary fire diesel discharge flange did not meet the thread engagement requirements of the maintenance procedure. These bolts were existing bolts that were installed before diesel was received. The vendor supplied new bolts and these bolts were installed following the procedural requirements.

- While perform VT-1 examination in February 2022, HNP found the inlet flange bolting (one stud, two nuts, and three washers) on the safety relief valve were unsatisfactory. The work order was changed to replace the safety relief valve (SRV) associated with the flange and included the replacement of the bolting components for the flange. However, the work was identified as preventive maintenance rather than corrective maintenance. The process for corrective maintenance included an ASME coordinator review. The work contingency placed a stop work hold until the review by the ASME coordinator was completed. The work was approved by the ASME coordinator and the hold was removed. The crew replaced the valve and bolting components and closed the work satisfactory.

AMP effectiveness will be assessed at least every five years per NEI 14-12. The last assessment verified that HNP has implemented the AMP elements during the period of extended operation. There were no findings associated with the Bolting Integrity AMP.

The Bolting Integrity 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 periodically evaluated.

Conclusion

The 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

Program Description

The Open-Cycle Cooling Water AMP, previously known as the Plant Service Water and RHR Service Water Inspection Program AMP, is an existing AMP that mitigates the aging effects of loss of material due to corrosion, erosion, cracking, and reduction of heat transfer due to fouling and biofouling in components exposed to raw water. The Open-Cycle Cooling Water AMP, like the previous Plant Service Water and RHR Service Water Inspection Program AMP, partially satisfies the requirements of NRC GL 89-13.

The following aging effects could occur to PSW and RHRSW passive components within the scope of SLR: loss of material, loss of heat exchanger performance, flow blockage (fouling), and cracking. The Open-Cycle Cooling Water AMP manages these effects for those components. This program is designed to detect wall thickness degradation, fouling, or cracking in the components associated with the PSW and RHRSW systems. The specific inspection locations in the PSW and RHRSW systems are based on a representative sample of the most susceptible locations. Locations determined to be prone to corrosion are infrequently used piping (stagnated water), submerged piping, piping with low fluid velocity, small diameter piping, backing rings, socket welds, and the heat affected zone of a weld.

Locations prone to clogging include those prone to corrosion, horizontal runs of piping at the bottom of vertical runs, intermittently used piping, and low point drains. Locations prone to cracking include locations susceptible to vibration fatigue and SCC. Locations prone to erosion include the areas with high velocity.

The Open-Cycle Cooling Water AMP inspection scope will include those portions of the following systems that are served by PSW and are within the scope of SLR:

- PSW system
- RHR system
- Containment Atmosphere Cooling System
- Control Building Heating, Ventilation, and Air Conditioning (HVAC) System
- Emergency Diesel Generators System
- Reactor Building HVAC System

The AMP includes injection of biocides and flushing as a preventive measure. The piping inspection program provides for visual and volumetric examinations intended to detect wall thinning, surface indications, and reduction of flow area within PSW and RHRSW system components. The Open-Cycle Cooling Water System AMP utilizes volumetric inspections (radiographic and ultrasonic) and visual inspections to detect loss of material aging effects. Volumetric inspections, visual inspections, and flow testing are utilized to detect flow blockage (fouling) and loss of heat exchanger performance. Engineering personnel track and trend inspection and test results in accordance with the Open-Cycle Cooling Water System AMP implementing procedures. Any unacceptable indication of loss of material will be evaluated by engineering. If warranted, additional testing or inspections will be performed. Any significant degradation of components inspected or tested by the implementing procedures is noted and corrective actions will be implemented in accordance with the CAP.

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. The inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

NUREG-2191 Consistency

The Open-Cycle Cooling Water System AMP, with enhancements, is 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 Open-Cycle Cooling Water AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
3 - Parameters Monitored/Inspected	Update the piping and heat exchanger inspection procedures to monitor for internal cracking in copper alloys with greater than 15 percent zinc.
4 - Detection of Aging Effects	Update the service water systems heat exchanger testing procedures to require the final heat exchanger testing frequency to be at least once every five years.
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 & Trending	Clarify in 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.
5 - Monitoring & Trending	Ensure the service water program and heat exchanger inspection procedures prompt an evaluation of the heat transfer capability of the safety-related, raw water supplied heat exchangers when fouling is identified.
5 - Monitoring & Trending	Ensure service water program and inspection procedures include trending of wall thickness measurements at locations susceptible to ongoing degradation due to specific aging mechanisms (e.g., microbiologically-induced corrosion (MIC)). Ensure the monitoring frequency and number of inspection locations is adjusted based on the trending.

7 - Corrective Actions	Update the service water program procedure and inspection and testing procedures to clarify that if fouling is identified, the overall effect is evaluated for flow blockage, loss of material, reduction in heat transfer, and chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC) or 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 service water 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 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. Regardless of which unit the condition is identified, the additional number of inspections will be performed on Unit 1 and Unit 2 where the same material, environment, and aging effect combination exists (each unit will perform a minimum of five additional inspections or 20 percent of each applicable material, environment, and aging effect combination, whichever is less).

Operating Experience

Industry Operating Experience

HNP 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 Open-Cycle Cooling Water AMP, as described in NUREG-2191, Section XI.M20.

- Loss of material due to corrosion (including MIC and erosion): (NRC IN 85-30, IN 2007-06, Licensee Event Reports (LER) 247/2001-006, LER 306/2004-001, LER 483/2005-002, LER 331/2006-003, LER 255/2007-002, LER 454/2007-002, LER 254/2011-001, LER 255/2013-001, LER 286/2014-002). HNP addresses the loss of material due to corrosion by taking preventive actions (i.e. system chemical injection) and monitoring/inspecting for corrosion conditions.

- Protective coating failure leading to unanticipated corrosion: (IN 85-24, IN 2007-06, LER 286/2002-001, LER 286/2011-003). HNP monitors for protective coating failures through the internal coatings/linings AMP.

- Reduction of heat transfer and flow blockage due to fouling in piping and heat exchangers as a result of 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). HNP performs heat transfer capability tests on applicable heat exchangers and the heat exchanger inspection procedures will be enhanced as discussed in element 7 to prompt an evaluation of heat transfer capability when fouling is identified.

- Cracking due to SCC in brass tubing (LER 305/2002-002). HNP will enhance their inspection procedures to monitor for internal cracking in copper alloys. HNP will enhance the heat exchanger inspection procedures as discussed in element 3 to monitor for internal cracking in copper alloys.

- Pitting in stainless steel (LER 247/2013-004). The HNP inspection procedures include checking tubes for signs of pitting and inspecting areas most susceptible to pipe wall degradation like the ones identified in this LER (i.e., weld areas and pipe elbows).

- Industry OE (INPO IER L3-20-3) identified a December 2019 industry event where the service water system at a plant (Cooper Nuclear Station) was declared inoperable due to flow blockage caused by at least 15 feet of river sediment covering the service water pipe outfall. HNP has a preventive maintenance procedure that inspects the intake structure for sediment.

<u>Plant Specific Operating Experience</u>

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In April 2013, while preparing PSW piping for UT, weeping of process fluid through the wall of piping was identified. The failure mechanism was postulated to be corrosion due to the creation of current eddies in this section of pipe. Immediate actions taken were to determine the structural integrity of the piping and expand the UT scope to five additional areas per the pipe condition monitoring program. The affected piping was determined to be structurally sound and the expanded UT inspections revealed no additional pipe wall issues. The leaking pipe was replaced in February 2014.

- In July 2013, a 6 drop per minute (dpm) leak was observed coming from under insulation while performing a leakage test. Further investigation revealed the leak coming from a 6x8 tee in the discharge pipe for the division 1 RHR and core spray pump room coolers. A monthly monitoring program was set up to monitor the leak and the metal thickness around the leak until the pipe could be replaced during the next refueling outage. The pipe was replaced in February 2014 with like material in accordance with the ASME XI Repair and Replacement Plan.

- In February 2020, the results of an RHR heat exchanger inspection showed evidence of erosion on the channel cover flow diverter, chipped protective coating, and foreign material debris. The conditions were identified in the CAP, characterized, and addressed per the SNC heat exchanger inspection program and ASME Section XI repair and replacement program. In March 2020, a modification was issued to install stacked gaskets and sealing material to conform to the gap between the flow diverter and cover channel cover. The protective coating was also verified to be intact and foreign material verified removed.

- In February 2020, eddy current testing on a RHR heat exchanger revealed indications on two tubes. The CR evaluation concluded the two tubes were required to be plugged. An evaluation was completed to confirm that plugging these two tubes will not result in exceeding the maximum tube plugging allowance for this heat exchanger. A work order was completed to plug the two tubes.

- In January 2021, a three dpm leak was identified on a diesel generator expansion joint located on a service water supply line. The diesel generator remained operable based on the small size of the leak compared to the total system flow and the expansion joint was scheduled for replacement during the next system outage. The expansion joint was replaced in May 2021.

- In February 2022, a pipe leak was observed on a one half inch diameter sensing line at a service water strainer. The leak was evaluated for operability and it was determined that operability was not impacted. The pipe leak was entered into the CAP process for resolution and the pipe was replaced in July 2022.

- In March 2022 during the last NRC Triennial Heat Sink Inspection, the PSW and RHRSW inspection procedures were challenged for adequacy when used on GL 89-13 heat exchanger inspections. Industry benchmarking was completed and found that the procedures were below the industry standard for documenting the results for the as-found/as-left inspections. Further investigation revealed that the preventive maintenance procedures (PM) that implement these inspections should reference the heat exchanger inspection program instead of the PSW and RHRSW inspection programs. The PMs were revised to reference the heat exchanger inspection program and the issue was resolved.

- In August of 2022 a CAR was generated concerning organizational issues allowing for corrosion in the U1 RHRSW piping. The discovered corrosion was supposed to be addressed in response to NRC GL 89-13, but no PMs were generated. In response to the CAR, HNP generated the necessary PMs with a 2-year frequency.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The Open-Cycle Cooling Water System AMP, with enhancements, provides 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

Program Description

The Closed Treated Water Systems AMP, previously known as the Closed Cooling Water Chemistry Control AMP, is an existing AMP that manages aging of the internal surfaces of piping, piping components, 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 of heat transfer. The program scope includes managing aging of the reactor building closed cooling water (RBCCW) system, the control building chilled water (CBCW) system, the emergency diesel generator jacket water (EDGJW) system, the reactor building and radwaste building chilled water (RBRWCW) system, and the primary containment chilled water (PCCW) system (Unit 2 only).

The Closed Treated Water Systems AMP is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. This AMP consists of (1) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion are minimized; (2) chemical testing of the water so that the water treatment program maintains the water chemistry within acceptable guidelines; and (3) inspections to determine the presence or extent of degradation. The RBCCW, CBCW, RBRWCW, and the PCCW systems use a nitrite/molybdate based chemical treatment program. The EDGJW system utilizes an inhibited glycol chemical treatment program.

To prevent loss of material, cracking, and reduction of heat transfer the Closed Treated Water System AMP periodically monitors water chemistry parameters and the condition of surfaces exposed to the water. The water chemistry parameters monitored and the acceptable range of values are in accordance with EPRI Closed Cooling Water Chemistry Guideline for non-glycol systems. For the EDGJW system, the parameters monitored are in accordance with the glycol solution vendor requirements. Heat transfer capability will be evaluated by visual inspections or functional testing.

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 HNP 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. 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 Closed Treated Water Systems AMP includes condition monitoring activities, which provide for periodic visual inspections and examination on a representative sample of piping and components that is selected based on likelihood of corrosion or cracking. Inspections will be performed whenever the system boundary is opened, and periodic inspections will be performed, at a minimum, on a 10-year frequency.

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. The inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

NUREG-2191 Consistency

The Closed Treated Water Systems AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.M21A, "Closed Treated Water Systems."

Exceptions to NUREG-2191

None.

Enhancements

The Closed Treated Water Systems AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
3 - Parameters Monitored/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.
3 - Parameters Monitored/Inspected	Update implementing procedure(s) to include monitoring frequencies that are in accordance with the latest version of the EPRI Closed Cooling Water Chemistry Guideline for non-glycol systems.
4 - Detection of Aging Effects	Update implementing procedure(s) or create new 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 procedure(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.
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. Corrective actions will include additional inspections. The number of increased inspections will be determined in accordance with the CAP; however, 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 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. The additional inspections include inspections at all of the HNP units that have the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. An example of this is the following:

- LER 280/1991-019 describes an event that involved degradation of CCCW systems due to through-wall cracks in supply lines causing loss of containment integrity.

  HNP has not experienced any loss of containment integrity events caused by cracking or corrosion of CCCW system components, based on the 10-year review of plant-specific OE discussed below.

- LER 327/1993-029 describes an event that involved degradation of CCCW systems due to corrosion product buildup in check valves.

HNP has not experienced significant corrosion product buildup, caused by oxide wedging, which can lead to inoperable check valves within CCCW systems, based on the 10-year review of plant-specific OE discussed below.

- LER 263/2014-001 describes an event that involved SCC of stainless steel reactor recirculation pump seal heat exchanger coils (attributed to localized boiling of the CCCW system which concentrated water impurities on coil surfaces).

  HNP has not experienced any SCC of stainless steel reactor recirculation pump seal heat exchanger coils attributed to localized boiling of the CCCW system, based on the 10-year review of plant-specific OE discussed below.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows.

- In May 2015, it was discovered that the Unit 2 PCCW and Unit 2 RBCCW systems were outside the EPRI pH limits for an extended amount of time. The EPRI limits for closed cooling water systems were set within a range for pH. The action level was to return the chemistry control parameters to within the normal operating range within 90 days. The PCCW pH was below the lower EPRI limit for 51 days and the RBCCW pH was below the lower EPRI limit for 41 days.

  In response to this event, HNP took several immediate actions. These actions included (1) immediately making a chemical addition to correct the pH parameter to back within EPRI range limits; (2) conducting a broadness review to ensure there were no other parameters outside of EPRI limits and none were identified; (3) performing a lessons learned review and discussion with all technicians; (4) chemical supervision review of out of limit range report; and (5) incorporation of this event into the next continuing training cycle.

- In November 2022, a LR self assessment was conducted which included assessing the Closed Cooling Water Chemistry Control AMP. The purpose of the assessment was to ensure the effectiveness of the LR AMPs. During the assessment, several objectives were addressed including verifying programs are reviewing applicable OE, verifying LR aging management commitments are maintained, verifying implementation activities, verifying aging effects are managed, and verifying corrective actions are generated. The Closed Cooling Water Chemistry Control program was identified as potentially missing a procedural commitment involving periodically analyzing RBCCW carbon steel coupons. However, per the program owner coupon testing was no longer being performed based on a technical justification provided in the CCW strategic plan.

  HNP revised the applicable procedure to remove coupon analysis from this procedure for the RBCCW and PCCW programs to align with the strategic plan. HNP also reviewed the applicable LR commitment for potential revision. No revision was required since coupons were not mentioned in the commitment. In addition, HNP generated a licensing document change request to track to completion revisions to the Unit 2 FSAR section for Closed Cooling Water Chemistry Control.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The Closed Treated Water Systems 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.2.3.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Program Description

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program, previously known as the Overhead Crane and Refueling Platform Inspection AMP, is an existing AMP that evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of SLR. This program addresses the inspection and monitoring of crane-related structures and components to provide reasonable assurance that the handling system does not affect the intended function of nearby safety-related equipment. Many crane systems and components are not within the scope of this program because they perform an intended function with moving parts or with a change in configuration, or they are subject to replacement based on qualified life.

The program includes periodic visual inspections to detect loss of material due to general corrosion 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” (Reference 1.6.21), provides specific guidance on the control of overhead heavy load cranes. The activities to manage aging effects specified in this program 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 1.6.22), which is referenced by NUREG–0612, or other appropriate standards in the ASME B30 series. In addition, monitoring and maintenance of structural components of crane handling systems follow the maintenance rule requirements provided in 10 CFR 50.65 for other crane types.

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP ensures the overhead crane and refueling platform are capable of safely handling loads. The aging management review for passive structural elements identified one aging effect, loss of material due to corrosion, as requiring management. This program also satisfies the requirements of the Unit 1 Technical Requirements Manual, which requires surveillance testing of the 5-ton hoist and the crane/hoist used for handling fuel assemblies or control rods.

NUREG-2191 Consistency

The 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.”

Exceptions to NUREG-2191

None.

Enhancements

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
4 - Detection of Aging Effects	Update the governing procedure and inspection procedures to specifically require visual inspectors to be visual testing technique (VT) qualified in accordance with plant-specific procedures and processes.
4 - Detection of Aging Effects	Update procedures to state the visual inspection frequencies required by the 1976 version of ASME B30.2. 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).
6 - Acceptance Criteria	Update the 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 is evaluated as required by ASME B30.2 other applicable industry standard in the ASME B30 series.
6 - Acceptance Criteria	Update the governing procedure to state that the acceptance criteria for steel structures and connections guidelines from the Structural Monitoring Program for the Maintenance shall be used.
7 - Corrective Actions	Update the governing procedure and inspection procedures to state that repairs made to NUREG-0612 load handling systems are performed as specified in the 1976 version of ASME B30.2.
6 - Acceptance Criteria 7 - Corrective Actions	Update procedures to state that any unacceptable indication of loss of material will be evaluated by engineering. When appropriate, engineering evaluations will be based upon the design code of record. If warranted, additional inspections will be performed. Any significant degradation of components is noted and corrective actions will be implemented in accordance with the CAP.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability 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 lifetime, 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

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In April 2013, the west bridge rail for the Unit 1 Turbine Building crane had loose bolting at a rail butt splice. Both the splice clamps and the clips to the support beam had loose bolting. It appeared that one of the bolts had been partly ground away on the bolt head. The degraded bolts along with nuts and washers were replaced and all bolts were torqued.

- In May 2013, review of ASME B30.2 and B30.10 guidelines for overhead crane inspections indicated “frequent” monthly inspections need only be visual inspections. Other “periodic” inspections and measurements are needed less frequently. The Overhead Crane Inspection procedure sections for mechanical inspection and electrical inspection for monthly inspections contained the required frequent visual inspections, but also contained periodic inspections which can be done less frequently. The procedure was revised to better align with the ASME guidelines for “frequent” and “periodic” inspections.

- In July 2013, a walkdown inspection of the east bridge rail found at least 2 loose bolts at a rail splice. This condition was added to an open work order for loose bolts on the west rail of this same crane. The work order was completed and the inspection was completed satisfactorily.

- In August 2013, while performing the monthly inspection on the Unit 1 Turbine Building Overhead Crane, a crack was found at the east end of the north rail beam on the inside webbing. The paint was gone and it appeared to have been welded before. This did not affect the operability of the crane. The weld was ground out, rewelded, and inspected satisfactorily. The area was re-primed and re-coated.

- In September 2015, the Unit 2 Refueling Platform southwest seismic restraint was identified as rubbing on the west side of the rail. This rubbing condition occurred mainly when moving in the reverse direction. When moving in the forward direction, no rubbing was identified. The Refueling Platform was still functional. Additional grout was removed from the trench area and underneath area of rail was verified to be clean of any grout. The Refueling Platform still exhibited some rubbing. After further investigation, it was determined that the southwest restraint was in contact with the side of the rail. The Refueling Platform could still be moved, but appeared to "crab" on the rails. A new bridge was installed and the work order was canceled.

- In October 2015, a review of the work order history for the U1 Reactor Building 228 Overhead Crane Inspection showed that the monthly PM was not performed for a three-month period, February through April of 2015. The work management module typically auto generates a work order for PMs 60 days prior to the due date. No work orders were generated during that timeframe. The cause was determined to be an issue within the work management module and was fixed with a newer version. An analysis of the PM database for additional instances of the event produced a list of 15-20 minor administrative items.
- In November 2022, while performing the annual PM on the U1 Turbine Building Crane, it was identified that the monorail was missing a support that has a guide roller attached to it. The welds for the support had broken and the support had fallen off. The work order is still open and scheduled to be worked in 2025.

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 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP. Findings were administrative in nature; general updates for references and inspection frequency inconsistencies were made in the AMP basis document.

The 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 periodically evaluated.

Conclusion

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems 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.2.3.14 Compressed Air Monitoring

Program Description

The Compressed Air Monitoring AMP is a new program which will inspect, monitor, and test the instrument and service air systems to provide reasonable assurance that the systems will perform their intended function.

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 will be managed through this AMP. Monitoring of moisture and other contaminants as a preventive measure to keep compressed air quality within specified limits will also be included.

This AMP will provide 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 inspections of compressed air system components located downstream of the compressed air system air dryers, or for components exposed to an internal gas environment to detect signs of corrosion and abnormal corrosion products that might indicate loss of material within the system will be performed in accordance with ASME OM-

2012, Division 2, Part 28.

The Compressed Air Monitoring AMP will incorporate the guidance from the most current ANSI/ISA standards, and the guidance from ASME OM 2012, Division 2, Part 28, and EPRI TR-108147 for testing and monitoring of 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 Compressed Air Monitoring AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M24, "Compressed Air Monitoring."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. An example of this is the following:

- Potentially significant safety-related problems pertaining to air systems have been documented in NRC IN 81-38, IN 87-28, IN 87-28, Supplement 1, and in Licensee Event Report 237/94-005-3. Some of the systems that have been significantly degraded or that have failed due to the problems in the air system include the decay heat removal, auxiliary feedwater, main steam isolation, containment isolation, and fuel pool seal systems. In 2008, one plant incurred an unplanned reactor trip from a failure of a mechanical joint in the instrument air system (NRC IN 2008-06). Nevertheless, as a result of NRC GL 88-14 and in consideration of Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01 and EPRI TR–108147, performance of air systems has improved significantly.

<u>Plant Specific Operating Experience</u>

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- At various times throughout the date range above, numerous CRs document dew point temperature readings that were outside of the acceptable range. It was determined that these out of range dew point readings were caused by instrumentation malfunctions within the instrument and service air systems rather than an actual out of range dew point condition. These CRs show that dew point is monitored and identified when out of range, but that the system is operating correctly and that air quality remains as expected.

- In June 2018, Unit 1 instrument air sampling was performed at various locations. All samples taken were above the desired dew point temperatures at the time of sampling. The cause was due to performance issues with the service air dryer, which normally pre-dries the compressed air that is supplied to the instrument air dryer. There was no impact to any system supplied by instrument air since there was a considerably large margin between the samples and the lowest expected ambient temperature. A work order was completed which repaired the air dryer and recalibrated the moisture analyzer.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The Compressed Air Monitoring 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.2.3.15 Fire Protection

Program Description

The Fire Protection AMP is an existing condition monitoring and performance monitoring program comprised of tests and inspections. License Amendments 304 and 249 to HNP Units 1 and 2 Operating Licenses, respectively, transitioned the fire protection AMP to a risk-informed performance-based program based on NFPA-805 in accordance with 10 CFR 50.48(c). The NRC issued the safety evaluation and approval via letter dated June 11, 2020 (ADAMS Accession number ML20066F592). These license amendments allowed performance-based inspection, testing, and maintenance frequencies to be established as described in EPRI Technical Report TR-1006756, “Fire Protection Surveillance Optimization and Maintenance Guide for Fire Protection Systems and Features,” dated July 2003.

The program manages loss of material for fire rated doors, fire dampers, and the CO_2 fire suppression system; cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors; and hardness and shrinkage of fire barrier penetration seals. Periodic visual inspections of credited fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual condition inspections and functional tests of fire rated doors are performed to ensure that they can perform their closure, latching, and barrier functions. Inspectors are qualified in accordance with plant procedures.

The program includes a periodic visual inspection of the fire barrier walls, ceilings, and floors, including fire resistance coatings and wraps (electrical raceway fire barrier system (ERFBS), fire stops, cable tray covers, and hatch covers examining for any signs of aging such as cracking, spalling, and loss of material. 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 caused by increased hardness and shrinkage of seal material due to weathering. If the inspection results do not meet the performance criteria, an engineering evaluation will be performed to determine if the barrier can still perform its intended fire protection function.

Inspection samples of fire barriers and fire rated penetration seals within the barriers must be selected. Approximately equal amount of accessible penetration seals and fire barriers are inspected on an annual frequency such that each barrier and penetration seal will be inspected at least once per 15 years which ensures that all penetration seals and fire barriers will be inspected at least once during the SPEO. Samples are influenced by areas that are only accessible during outages.

The program includes periodic visual inspection and closure tests on fire dampers to ensure timely detection of damage to dampers which could prevent the system from performing its intended function. Fire damper inspection results are acceptable if there are no visual indications of loss of material that would prevent the barrier from restricting air flow when tripped.

The program includes a periodic visual inspection and functional test on fire-rated doors to verify the integrity of door surfaces and for adequate clearances to detect aging of the fire doors prior to the loss of intended function. The visual inspection and functional test include observation for wear, loss of material, inadequate clearances, and missing parts. Fire door inspection results are acceptable if there are no visual indications of missing parts, holes, loss of material, or wear and no deficiencies in the functional tests performed for checking clearances and proper closure.

Visual inspections are performed by the External Surfaces Monitoring of Mechanical Components AMP (B.2.3.23) to identify conditions of corrosion and mechanical damage in the CO_2 flow path. A periodic functional test of the CO_2 fire suppression system is performed. The functional tests require deficiencies to be entered into the CAP, corrected and the system retested to verify functionality.

NUREG-2191 Consistency

The Fire Protection AMP is consistent without exception and no enhancements, with the 10 elements of NUREG-2191, Section XI.M26, "Fire Protection."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

- 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). HNP did not response with a letter to the NRC as none was required. However, the procedure references the INs. In addition, all penetrations are inspected over the 15-year period per fire barrier and seal procedures.

- Degradation of electrical raceway fire barrier such as small holes, cracking, and unfilled seals are found on routine walkdown (NRC IN 91-47 and NRC GL 92-08). In response to GL 92-08, HNP will no longer credit Thermos-Lag® as a fire barrier material.
- Fire doors have experienced wear of the hinges and handles. HNP fire doors are inspect per the fire door procedures to inspect for degradation of the fire door including hinges and handles. Any degradation noted will generate a corrective action.

HNP has identified deficiencies as noted in the NRC INs and GL. All the deficiencies were appropriately processed through the OE program and CR were generated, when necessary. In the following section, HNP lists several CRs associated with fire door degradation and seals degradation.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation.

- During the OE search there was over 200 CRs related to fire doors. The majority of the degradation of the doors was concerned with closing mechanisms, door handles and hinges. All CRs repaired the doors to operational status to maintain a fire barrier function. One CR of note was reported concerning a broken fire door itself. The door was replaced appropriately, and the fire barrier function was maintained.
- During the OE search, approximately 100 CRs were generated concerning fire penetrations degradation, concrete and sealant cracking, and gaps such as shrinkage, cracking, and missing sealant. The penetrations were promptly replaced or repaired. In addition, many of the said CRs also noted cracks in concrete walls, floors, and ceiling. The cracks were all evaluated and repaired as needed to maintain the proper fire barrier design basis.
- In August 2014, three 1/2-inch holes were identified going into the void within a concrete masonry unit (CMU) block wall. Due to the multiple holes within the wall the 3-hour fire rating was no longer being maintained and the wall was considered non-functional until it was repaired with grout in November 2014.
- In March 2018, HNP discovered an expansion joint with chunks of FOAMGLAS® material missing interior to the gap. The concrete overcoat was missing along the length of the wall in the vertical direction. The joint material was evaluated and lines were removed on either side of the joint. Then the joint was resealed with foam.

These examples demonstrate that the inspections executed under the Fire Protection AMP scheduled/opportunistic inspections, and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

Integrated Inspection Reports

A review of the integrated inspections performed by the NRC since 2019 identified one NRC inspection of the fire protection AMP from LR. The inspection included a fire door and a fire damper. The NRC found no issues with the two fire protection systems and components related to aging management.

Effectiveness/Post-Approval Reviews

AMP effectiveness is assessed at least every five years per NEI 14-12.

The 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 Fire Protection AMP is periodically evaluated.

Conclusion

The Fire Protection 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 Fire Protection AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.16 Fire Water System

Program Description

The Fire Water System AMP is an existing AMP. This AMP manages the aging effects of loss of material, wall thinning, hardening or loss of strength, and flow blockage due to fouling for water-based fire protection system components. This objective is achieved through conducting periodic visual inspections, tests, volumetric inspection, continuous monitoring of system pressure, and system flushes performed in accordance with the HNP procedures. Inspection and test frequencies are governed by the NRC approved fire protection program as stated in the National Fire Protection Association Code (NFPA) 805 Safety Evaluation Report (ML20066F592). Potential future changes to the frequencies of inspections and testing would be done in accordance with the approved NFPA 805 program and site procedures.

The Fire Water System AMP applies to water-based fire protection system components, including closed head sprinklers, open head sprinklers and spray nozzles, valve bodies, fire pump casings, hydrants, passive components of the hose stations, standpipes, and aboveground and buried piping and components that are tested in accordance with the NFPA codes and standards. Two diesel driven fire pumps and the electric-driven fire water pump do not have any suction screens since the water is demineralized prior to entering the fire water storage tanks. HNP does not have foam water sprinkler systems or glass bulb sprinklers within the scope of SLR. Full-flow testing and visual inspections are conducted in order to provide reasonable assurance that aging effects 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 pre-action sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect, are subjected to augmented testing or inspections.

The wet pipe sprinkler systems are not exposed to any harsh or corrosive environments as defined in NFPA 25 Section 5.3.1.1.2 and Section A.5.3.1.1.2 of Annex A of NFPA 25. The wet pipe sprinklers are exposed only to an external environment of plant indoor air and internal environments of raw water.

The 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 Bolting Integrity AMP (B.2.3.10) will manage loss of preload and loss of material for fire water system closure bolting. The 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. The 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. The Fuel Oil Chemistry AMP (B.2.3.18) manages loss of material for fire water components that are exposed to a fuel oil. Some fire water system piping sections are internally coated with cementitious coatings. Visual examinations of these coatings for indications of loss of material or cracking are not performed by the Fire Water System AMP, but rather those coatings are managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section B.2.3.28).

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 removed 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.

To address potential aging effects, the Fire Water System AMP monitors several fire water system parameters. Periodic fire pump capacity testing is performed and the system pressure is continuously monitored. Additionally, periodic fire water system flow testing and flushing are 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.

HNP has two fire water storage tanks that supply fire water to the system. The tanks are periodically inspected and cleaned to ensure there is no aging effects that would cause a loss of intended function. The fire water storage tanks are internally coated. The coatings are periodically inspected for coating degradation/failure that could result in a loss of any component intended function. These coatings inspections are performed in conjunction with the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (Section 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 in accordance with NUREG-2191, Table XI.M27-1, “Fire Water System Inspection and Testing Recommendations.” With respect to aging effect detection, the 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.
- Visual and volumetric periodic inspections of the fire water storage tanks.

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.

The fire water system pressure is continuously monitored through alarm setpoints in the main control room. The system pressure is maintained using the jockey pump or the electric fire pump which can alert operators to a potential leak. 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.

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. The inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes.

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 CAP. Acceptance criteria for observed degradation, flow obstruction, discharge flow/pressures, or minimum wall thickness are defined in the Fire Water System AMP procedures used to perform the respective inspections and tests. Enhancements necessary to the HNP procedures to implement the recommendations listed in NUREG-2191 Table XI.M27-1 are outlined below.

<u>Sprinkler Head Inspections</u>

- HNP will provide technical justification that will demonstrate the water is not corrosive to the sprinklers based on past testing results so that sprinkler head testing and replacement requirements can be removed from the sprinkler head inspection procedure per NUREG-2191 Table XI.M27-1 Note (e).

<u>Flow Tests</u>

- A flow test will be conducted in the 5 year period prior to the SPEO at the hydraulically most remote hose connection of each building to verify the water supply. Where a flow test of the hydraulically most remote hose connection is not practical, the engineering will be consulted for the appropriate location for the test. Subsequent tests at the most remote hose connection during the SPEO will be conducted every 5 years on a representative sample of 20 percent of the population (defined as components having the same material and environment combination) or a maximum of 25 per population at each unit.

<u>Water Storage Tanks - Interior Inspections</u>

- If there are signs of degradation of the fire water storage tanks, volumetric Inspections or low-frequency electromagnetic tests will be performed. Tank bottoms will be tested for loss of material on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion. An acceptable alternative to ultrasonic testing is the removal, visual inspection, and replacement of random floor coupons.

- When there are signs or age-related degradation detected in the vicinity of welds, the tank shall be vacuum-box tested at bottom seams in accordance with test procedures found in NFPA 22.
- The fire water storage tanks will have the bottom surfaces inspected. Specifically, for each 10-year period starting 10 years before the SPEO, low-frequency electromagnetic testing or volumetric inspection of the tank bottom will be performed from the inside surface of the tanks. Any regions below nominal plate thickness (in excess of plate manufacturing tolerance) will have a follow-up ultrasonic thickness reading. If there are areas of significant loss of material that could impact the pressure boundary function, future ultrasonic thickness measurements and trending will be performed.

Main Drain Tests

- 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. To identify whether significant degradation of the fire water system supply has been occurring over several years, test-to-test pressure monitoring full flow pressures will not be compared only to the immediately prior test results.

Obstruction Investigation - Obstruction Investigation and Prevention

- An obstruction investigation shall be conducted for system or yard main piping wherever any of the following conditions exist:
    - The discharge of obstructive material during routine water tests
    - Foreign materials in fire pumps, in dry pipe valves, or in check valves
    - Foreign material in water during drain tests or plugging of inspector’s test connection(s)
    - Plugged sprinklers
    - Plugged piping in sprinkler systems dismantled during building alterations
    - Pinhole leaks
    - 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.

If any of the above obstruction conditions are present, HNP will initiate a CR and will be investigated and resolved through the CAP.

NUREG-2191 Consistency

The Fire Water System AMP, with enhancements, will be consistent with exceptions to the 10 elements of NUREG-2191, Section XI.M27, “Fire Water System.”

Exceptions to NUREG-2191

Exception 1. Element 4

NUREG-2191 Section XI.M27 recommends sprinkler inspection be performed on an annual frequency to identify any degradation of the sprinklers. HNP currently inspects the sprinklers using performance-based methodology outlined in EPRI 1006756, "Fire Protection Surveillance Optimization and Maintenance Guide for Fire Protection Systems and Features," and NFPA 805 program. HNP takes an exception to the frequency and will continue to use the current frequencies as follows:

1. Each open head sprinkler system will be inspected at least once per 4 years by performing an air flow test through each open head spray and sprinkler header and verifying each open head spray and sprinkler nozzle is unobstructed.
2. A visual inspection to verify each nozzle's spray pattern will be performed at least once every 4 years.
3. All systems in high radiation areas will be inspected at least once per 4 years by performing a system functional test which includes simulated automatic actuation.
4. All other systems will be inspected at least once per 3 years by performing a system functional test which includes simulated automatic actuation.

Exception 2. Element 7

HNP will take an exception to conducting no fewer than two additional inspections 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 CAP will evaluate any failed tests and determine the appropriate corrective actions and additional testing required.

Justification for Exceptions

Justification for Exception 1, Element 4

HNP evaluations document the evaluation and justification to increase the testing and inspection intervals for the sprinklers up to two refueling cycles or 48 months. EPRI 1006756 recommends a maximum allowable five percent failure rate for all suppression system piping, hanger, and nozzles. For the suppression system piping hanger and nozzle inspections, a failure rate less than five percent was established using the methodology outlined in EPRI 1006756. The historical data evaluated identified no failures recorded during the conduct of the inspections. Based on the historical data and results of the failure rates, the goal of a maximum failure rate of less than five percent is met for the testing and inspections of the sprinkler systems. The increased inspection intervals will have no impact on functionality of the suppression system.

Justification for Exception 2, Element 7

The CAP has demonstrated effectiveness at ensuring that the Fire Water System AMP adequately manages the effects of aging. Inspections that do not meet acceptance criteria are entered into the CAP. The fire protection inspection procedural guidance requiring engineering evaluation to determine which, if any, further inspections are required. The CAP provides guidance for addressing extent of condition and adjusting either frequency or quantities of inspections or tests based on NEIL, NFPA, and EPRI industry guidance.

Enhancements

The Fire Water System AMP will be enhanced as follows for alignment with NUREG-2191.

Element	Enhancement
2 - Preventive Actions	Clarify the fire water storage tank inspection procedure to specifically discuss inspection of the quality of the caulking or sealant at the tanks' foundation interface.
3 - Parameters Monitored/Inspected	Update sprinkler inspection procedures and create preventive maintenance items to perform volumetric wall thickness inspections of the normally dry piping or piping segments that allow water to collect.
4 - Detection of Aging Effects	HNP will provide technical justification that will demonstrate the water is not corrosive to the sprinklers based on past testing results so that sprinkler head testing and replacement requirements can be removed from the sprinkler head inspection procedure per NUREG-2191 Table XI.M27-1 Note (e).
4 - Detection of Aging Effects	Update sprinkler inspection procedures and create preventive maintenance items to include augmented inspection and testing requirements for dry pipe and pre-action sprinkler piping segments that cannot be drained or allow water to collect.
4 - Detection of Aging Effects	Update the flow test procedure to state flow tests will be conducted in the 5 year period prior to the SPEO at the hydraulically most remote hose connection of each building to verify the water supply. Where a flow test of the hydraulically most remote hose connection is not practical, engineering will be consulted for the appropriate location for the test. Subsequent tests at the most remote hose connection during the SPEO will be conducted every 5 years on a representative sample of 20 percent of the population (defined as components having the same material and environment combination) or a maximum of 25 per population at each unit.
4 - Detection of Aging Effects	Update the fire water storage tank inspection procedure and create preventive maintenance items to state if there are signs of degradation of the fire water storage tanks, volumetric Inspections or low-frequency electromagnetic tests will be performed. Tank bottoms will be tested for loss of material on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion. An acceptable alternative to ultrasonic testing is the removal, visual inspection, and replacement of random floor coupons.

4 - Detection of Aging Effects	Update the fire water storage tank inspection procedure and create preventive maintenance items to state when there are signs or age-related degradation detected in the vicinity of welds, the tank shall be vacuum-box tested at bottom seams in accordance with test procedures found in NFPA 22.
4 - Detection of Aging Effects	Update the fire water storage tank inspection procedure and create preventive maintenance items to state the fire water storage tanks will have the bottom surfaces inspected. Specifically, for each 10-year period starting 10 years before the SPEO, low-frequency electromagnetic testing or volumetric inspection of the tank bottom will be performed from the inside surface of the tanks. Any regions below nominal plate thickness (in excess of plate manufacturing tolerance) will have a follow-up ultrasonic thickness reading. If there are areas of significant loss of material that could impact the pressure boundary function, future ultrasonic thickness measurements and trending will be performed.
4 - Detection of Aging Effects	Update the main drain tests inspection to state 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.

4 - Detection of Aging Effects	Update inspection procedures to include an inspection of piping and branch line conditions shall be conducted 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. • Alternative nondestructive examination methods [that can ensure that flow blockage will not occur] are permitted. • Tubercules or slime, if found, shall be tested for indications of microbiologically influenced corrosion (MIC). • 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 NFPA 25 Section 14.3. • Inspection of a cross main is not required where the system does not have a means of inspection. • 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.
4 - Detection of Aging Effects	Update inspection procedures to include the following recommendations that would initiate an obstructions investigation: 1. The discharge of obstructive material during routine water tests 2. Foreign materials in fire pumps, in dry pipe valves, or in check valves 3. Foreign material in water during drain tests or plugging of inspector's test connection(s) 4. Plugged sprinklers 5. Plugged piping in sprinkler systems dismantled during building alterations 6. Pinhole leaks 7. 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. If any of the above obstruction conditions are present, HNP will initiate a CR and will be investigated and resolved through the CAP.

5 - Monitoring & Trending	Clarify inspection procedures to require monitoring and trending of data to confirm that components will maintain their intended functions throughout the SPEO based on projected rate and extent of degradation if degradation is identified.
6 - Acceptance Criteria	Clarify inspection procedures to measure wall thickness to compare the wall thickness to the minimum design if there is degradation identified. Wall thicknesses less than the minimum design will be entered into the CAP process for engineering evaluation.
6 - Acceptance Criteria	Clarify inspection procedures to demonstrate that no loose fouling products exist in the systems that could cause flow blockage in the sprinklers or deluge nozzles.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. The following industry OE is relevant to the Fire Water System AMP:

- In October 2004, a fire main failed its periodic flow test due to a low cleanliness factor. The low cleanliness factor was attributed to fouling because of an accumulation of corrosion products on the interior of the pipe wall and tuberculation. Subsequent chemical cleaning to remove the corrosion products from the pipe wall revealed several leaks. Corrosion products removed during the chemical cleaning were observed to settle out in normally stagnant sections of the water-based fire protection system, resulting in flow blockages in small diameter piping and valve leak-by. (Discussions as part of RAIs are available at ADAMS Accession Nos. ML12220A162, ML12306A332, and ML13029A244).

- In October 2010, a portion of a pre-action 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. (ADAMS Accession No. ML13014A100).

- In August 2011, an intake fire protection pre-action 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 (ADAMS Accession No. ML113050425).

- In March 2012, the staff and licensee personnel found that a portion of the internally galvanized piping of a 6-inch pre-action 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 (IN 2013-06).

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows.

- In March 2018, this condition report was written as a cognitive trend for the underground water leaks. The fire water underground system had eight leaks at various locations throughout the system. These individual leaks were captured in separate condition reports. Six leaks were associated with fire hydrant locations. Two leaks were associated with different locations in the fire loop header piping. A condition report documented the aggregate number of leaks and identify the need to escalate the repairs to determine the extent of condition. The following is a list of the work orders from the condition report that are associated with the underground fire water system which are related to possible aging or corrosion issues:
    - In August 2017, maintenance personnel determined a hydrant needed to be replaced since it was not able to be repaired. The valve on the hydrant was stuck and unable to be opened. The hydrant was replaced in April 2023, and a system flush was performed with no leakage noted.
    - In November 2017, the plant walkdown identified water coming up from the ground near a hydrant. The hydrant was replaced in November 2019 and there was no leakage detected after installation and system flush.
    - In November 2017, the plant identified two threaded rods between the vertical pipe flanges had corroded. In June 2018, a work order was initiated to repair the piping under the insulation. An evaluation of the rods determined the rods are not significantly rusted compared with the piping but all still needed to be replaced or repaired. The rod metal condition appeared to have changed in composition. In June 2018, the threaded rods were replaced, and the piping was repaired.

- In January 2019, the fire water system had a significant drop in pressure which resulted in a pressure perturbation that caused a fracture in the cooling tower underground fire protection piping with a full pipe rupture occurring four hours after the pressure event and the plant entered a limited condition of operation. Upon inspection of the piping, corrosion was ruled out due to no wall thinning or through wall leakage evidence. As a result of this event, HNP revised their procedures and provided additional training as discussed below. Procedure changes were initiated in February 2019 to identify training needs and procedure issues. Weaknesses were found in fire protection water suppression system flow test procedure as follows.
    - As a result of the event in January 2019, an evaluation was initiated to identify the procedures required to be revised to ensure one fire pump is in auto at all times. The fire protection suppression system procedure was the only procedure revision required. The procedure was revised to use the electric motor driven fire pump and keep both diesel driven fire pumps in standby and automatically available if an unexpected pressure drop occurs during performance of the surveillance.
    - At no time in the procedure was there direction to monitor for changes in fire water storage tank level. Only a caution to secure the test if level falls below 270,000 gallons. This caution did not refer to which indicators should be used for monitoring level to meet the requirements. The procedure was revised to ensure the tank level is monitored at all times during surveillances using local indicators rather than the main control room indications.
    - Calibration of the fire water storage tank local indications was performed since they are generally used as backup indications to verify electric alarm signals. The

indicators would be calibrated on a semi-annual basis ensure that the fire tanks level indicators are tested in accordance with NFPA 72D requirements. The instruments in the control room are not used for compliance with the surveillance to ensure fire water storage tank level.

- In November 2022, boroscoping of sprinkler system in the south HVAC room on the 164' reactor building revealed a large amount of sediment in the piping system. A work order was initiated to remove the sediment. The work order was completed satisfactory with no sediment noted after flushing.

Fire Water Storage Tank OE

- In May 2019, during internal inspection and examination of a fire water storage tank, a large bore vertical pipe approximately 8-inch in diameter, identified as an overflow line internal to the tank, had excessive corrosion along one side. The corrosion was located on along west side of the pipe, for approximately 20 feet. As a result of the observed corrosion, ultrasonic thickness measurements were performed on the inside of the overflow piping. These measurements determined that the wall thickness observed on the degraded inside overflow pipe met the criteria specified by American Society for Testing and Materials A53. Therefore, the corrosion observed on the inside overflow piping was considered to be surface corrosion and the inside overflow pipe remained fully capable of performing its specified function. The evaluation determined the as-is condition of the piping was acceptable and there were no corrective actions taken.

- In May 2020, the annual inspection of the fire water storage tanks was performed. The inspection identified the following degradation conditions and presented the evaluations of the degraded conditions for the fire water storage tanks.

  Fire Water Storage Tank 'A'
  Examination of area after insulation removal: the examination identified loss of coating to approximately 90 percent of the surface area of the 6-inch line. The loss of coatings allowed atmospheric conditions to degrade the pipe surface with localized areas of pitting, spalling, flaking, and delamination of coating. Further examination for wall thickness with UT, determined the wall thickness met the criteria specified by ANSI B31.1.

  Additional insulation was removed from the 10-inch line was identified with the same loss of coating due to atmospheric conditions degrading the surface of the pipe. The loss of coatings had allowed atmospheric conditions to degrade the pipe surface with localized areas of pitting, spalling, flaking, and delamination of coating. Further examination for wall thickness with UT, identified the wall thickness met the criteria specified in ANSI B31.1.

  Fire Water Storage Tank 'B'
  Examination of area after insulation removal, the examination identified loss of coating to approximately 80 percent of the surface area of the 6-inch line. The loss of coatings has allowed atmospheric conditions to degrade the pipe surface with localized areas of pitting, spalling, flaking, and delamination of coating. Further examination for wall thickness with UT, identified the wall thickness met the criteria specified in ANSI B31.1.

  Additional insulation was removed from the 10-inch line was identified with the same loss of coating due to atmospheric conditions degrading the surface of the pipe. The loss of coatings had allowed atmospheric conditions to degrade the pipe surface with localized areas of pitting, spalling, flaking, and delamination of coating. Further examination for wall thickness with UT, identified the wall thickness met the criteria specified in ANSI B31.1.

- In March 2022, work was conducted and inspection of insulation for the fire water system found that the aluminum housing providing insulation protection on the piping coming from a valve at the base of the fire water storage tank was degraded but functional in the as-is condition. Therefore, there was no corrective actions taken to repair the tank. In addition, a minor puncture approximately 1/2 inch across was observed on the return line insulation to the fire water storage tank 'B' and a degraded patch of insulation cover was observed on the return line to the fire water storage tank 'A'. Both return lines to the tanks are heat traced. An evaluation determined the degraded insulation did not represent a condition that would prevent a flow path from the fire protection pumps to the various fire suppression areas. Therefore, there was reasonable expectation the fire suppression system would still perform fire suppression function and no repairs to the as-is condition were needed.

- In June 2024, HNP performed corrective maintenance on the caulking installed at the concrete basemat interface of the fire water storage tanks at Units 1 and 2. The caulking was installed successfully. This corrective maintenance work order demonstrates that the Fire Water AMP is effective in ensuring the tanks, including the caulking interface with the concrete basemat are routinely inspected and repaired as necessary to prevent age related degradation of the fire water tanks

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The Fire Water System 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.2.3.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The Outdoor and Large Atmospheric Metallic Storage Tanks AMP, previously known as the Condensate Storage Tank Inspection AMP, is an existing condition monitoring program that manages the aging effects of loss of material and cracking due to corrosion. The scope of this program includes the Unit 1 and Unit 2 condensate storage tanks (CSTs). The Unit 1 CST is fabricated from aluminum and the Unit 2 CST is fabricated from stainless steel. The tank materials are exposed to air/condensation, concrete, and treated water. This program is designed to detect wall thickness degradation and cracking in the tanks associated with this AMP. The specific inspection locations in the CSTs are based on a representative sample of the most susceptible locations. Locations determined to be prone to corrosion are outside surfaces, bottom, inside surfaces, standpipes, supports, and nozzles.

The tank inspection program provides for visual, volumetric, and ultrasonic testing (UT) examinations intended to detect wall thinning and cracking on the CSTs. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance plant-specific procedures including parameters such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. Any unacceptable indication of loss of material or cracking will be evaluated by engineering. If warranted, additional inspections will be performed. Any significant degradation of the CSTs inspected by the implementing procedures is noted and corrective actions will be implemented in accordance with the CAP.

Table B.2.3.17-1, Tank Inspection Recommendations(b)

Material	Environment	Aging Effect Requiring Management (AERM)	Inspection Technique (f)	Inspection Frequency
Inspections to Identify Degradation of Inside Surfaces of Tank Shell, Roof(c), and Bottom(d, e)				
Stainless steel	Air, condensation	Loss of material	Visual	Each refueling outage interval or one-time inspection
		Cracking	Surface(i)	Each 10-year period starting 10 years before the SPEO, or one-time inspection
	Treated water	Loss of material	Visual from the inside surface or volumetric from the outside surface(g)	One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32
Aluminum	Air, condensation	Loss of material	Visual	Each 10-year period starting 10 years before the SPEO, or one-time inspection
		Cracking	Surface(i)	Each 10-year period starting 10 years before the SPEO, or demonstrate that SCC is not an applicable aging effect
	Treated water	Loss of material	Visual from the inside surface or volumetric from the outside surface(g)	One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32
Inspections to Identify Degradation of External Surfaces of Tank Shell, Roof, and Bottom				
Stainless steel	Air, condensation	Loss of material	Visual from the outside surface	Each refueling outage interval or one-time inspection
		Cracking	Surface(i)	Each 10-year period starting 10 years before the SPEO or one-time inspection
	Concrete	Loss of material	Volumetric from inside surface	Each 10-year period starting 10 years before the SPEO
		Cracking	Volumetric from inside surface	

Table B.2.3.17-1, Tank Inspection Recommendations(b)				
Aluminum	Air, condensation	Cracking	Surface(i)	Each 10-year period starting 10 years before the SPEO or demonstrate that SCC is not an applicable aging effect
		Loss of material	Visual from outside surface	Each 10-year period starting 10 years before the SPEO, or one-time inspection
	Concrete	Loss of material	Volumetric from inside surface	Each 10-year period starting 10 years before the SPEO
		Cracking	Volumetric from inside surface	Each 10-year period starting 10 years before the SPEO or demonstrate that SCC is not an applicable aging effect

Table B.2.3.17-1, Tank Inspection Recommendations(b)
Notes (a) Not used. (b) When one-time internal inspections in accordance with these footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 5-year period before the start of the SPEO. (c) Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces based on the material, environment, and AERM. (d) Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom cover all the inside surfaces. Where this is not possible because of the tank's configuration (e.g., tanks with floating covers or bladders), the SLRA includes a justification for how aging effects will be detected before the loss of the tank's intended function. (e) For tank configurations in which deleterious materials could accumulate on the tank bottom (e.g., sediment, silt),the internal inspections of the tank's bottom include inspections of the side wall of the tank up to the top of the sludge-affected region. (f) Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated to be effective at detecting the aging effects requiring management and a sufficient amount of the surface is inspected to provide reasonable assurance that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low-frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom. (g) At least 20 percent of the tank's internal surface is to be inspected using a method capable of precisely determining wall thickness. The inspection method is capable of detecting both general and pitting corrosion and is demonstrated to be effective by the applicant. (h) Not used. (i) A minimum of either 25 sections of the tank's surface (e.g., 1 square foot sections for tank surfaces, 1 linear foot sections of weld length) or 20 percent of the tank's surface is examined. The sample inspection points are distributed in such a way that inspections occur in the areas most susceptible to degradation (e.g., areas in which contaminants could collect, inlet and outlet nozzles, welds). (j) Not used. (k) Not used. (l) Not used.

NUREG-2191 Consistency

The Outdoor and Large Atmospheric Metallic Storage Tanks AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.29, "Outdoor and Large Atmospheric Metallic Storage Tanks."

Exceptions to NUREG-2191

None.

Enhancements

The AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
4 - Detection of Aging Effects	Update the AMP implementation procedure title to reflect that this AMP requires more than visual examinations on the CSTs. This procedure references other examination types used in CST examinations that satisfy the requirements of the current LR.
4 - Detection of Aging Effects	Update section 2.0 of the AMP implementation procedure to reflect the applicability and frequency of the inspections to Table B.2.3.17-1.
4 - Detection of Aging Effects	Update the AMP implementation procedure examination checklist to include inspection areas exposed to all tank environments in Table B.2.3.17-1 (i.e., ensure test sample group includes tank wall areas exposed to air/condensation, concrete, and water).
4 - Detection of Aging Effects	Perform an internal volumetric inspection of the tank bottom for loss of material and cracking. The frequency will be set in accordance with Table B.2.3.17-1, which is “each 10-year period starting 10 years before the SPEO,” or as noted in footnote (b), "When one-time internal inspections are used in lieu of periodic inspections, the one-time inspection must occur within the 5-year period before the SPEO."
5 - Monitoring & Trending	Enhance the AMP implementation procedure to include the following: when degraded conditions are identified, acceptability of the condition is projected to the next scheduled inspection or in the case of one-time inspections, follow-up inspections are scheduled.
5 - Monitoring & Trending	Enhance the AMP implementation procedure to include the following: results are evaluated against acceptance criteria to confirm or adjust timing of subsequent inspections, or in the case of one-time inspections, schedule follow-up inspections.

6 - Acceptance Criteria	Enhance the examination section of the AMP implementation procedure to include the coated areas for examination and to add a specific examination task to inspect the condition of coatings, sealants, and caulking along with physical manipulation of sealants and caulking.
7 - Corrective Actions	Enhance the sample set expansion requirements of the AMP implementation procedure to state the number of increased inspections is determined in accordance with the site's CAP. However, for other sampling-based inspections (e.g., 20 percent, 25 locations) the smaller of five additional inspections or 20 percent of the inspection population will be conducted. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause will be conducted to determine the further extent of inspection.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. A review of industry OE reveals that there have been instances involving defects variously described as wall thinning, pinhole leaks, cracks, and through-wall flaws in tanks. In addition, internal blistering, delamination of coatings, rust stains, and holidays have been found on the bottom of tanks.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covered the last 10 years of operation. Relevant OE items are as follows:

- In May 2015, the silica level in the Unit 2 CST was found to be above the administrative limit of 20 parts per billion (ppb). The elevated silica level was expected since the tank was recently drained down. Since this was an expected condition, no additional actions were required and the information was used for water quality trending.
- In July 2016, an LR coatings inspection on the Unit 2 CST revealed corrosion and possible material degradation on the tank hold-down "J" bolts. The initial evaluation was the corrosion was cosmetic and there was no significant loss of bolt material. The evaluation also concluded that the tank is structurally functional with two bolts degraded. The bolts were cleaned, reinspected, and evaluated for required additional actions. The inspection performed revealed the two bolts have degradation area of 0.100-inch diameter within the bottom two inches of bolt height, which was deemed acceptable. It was concluded the bolt condition was acceptable as-is.
- In November 2017, a U-bolt and nut were found during a foreign material exclusion inspection by divers before performing a Unit 2 CST LR inspection. The source of the bolt and nut was undetermined but they were removed from the tank.

- In December 2017, concrete splatter was identified in several locations around the perimeter of the Unit 2 CST. The initial conclusion stated concrete splatter was in random locations and there is no apparent damage to the tank integrity. The concrete splatter was cleaned, the tank was inspected for linear indications via visual and liquid penetrant examinations, and a UT exam was performed to determine wall thickness. The examinations did not reveal any linear indications or cracking on the tank walls and all UT measurements showed satisfactory tank wall thickness.
- In May 2021, while walking down the Unit 1 CST investigating a tritium leak, a pool of water was found near the bottom of the tank. No active leak was found, however, water was found puddling around the CST. A work order was issued to inspect and clean the inside of the CST and perform any required coating repairs. Engineering reviewed the inspection areas of interest and determined which areas required coating repairs. The coating repairs were completed and retests were satisfactory. Actions were taken to include the repair areas in future tank inspections and an enhancement was added to this AMP to update the tank inspection procedure to include this inspection scope.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Outdoor and Large Atmospheric Metallic Storage Tanks 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 periodically evaluated.

Conclusion

The Outdoor and Large Atmospheric Metallic Storage Tanks AMP, with enhancements, provides 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.2.3.18 Fuel Oil Chemistry

Program Description

The 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, visual inspections on the internal surfaces of the fuel oil storage tanks (FOSTs) and the diesel generator day tanks. Volumetric examinations will be performed on the fire pump diesel storage tanks in lieu of visual examinations. Volumetric thickness measurements will be performed on the FOST and the diesel generator day tanks when there are signs of corrosion. Volumetric inspections and thickness measurements are performed ensuring the tank bottom and other areas where sludge may build up are included to the extent possible.

The 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 aging management effects are minimal. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the HNP Technical Specifications and Technical Requirements Manual. Guidelines of the ASTM Standards are also used. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining and cleaning of tanks, addition of microbiocide, 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 One-Time Inspection AMP (Section B.2.3.20) is also used to verify the effectiveness and supplement this AMP.

Components within the scope of the Fuel Oil Chemistry AMP are fuel oil tanks, and piping, and other metal components subject to aging management review that are exposed to an environment of diesel fuel oil. The tanks within the scope of this AMP are the FOSTs, diesel generator day tanks, and the fire pump diesel storage tanks.

NUREG-2191 Consistency

The Fuel Oil Chemistry AMP, with enhancements, will be consistent with the 10 elements of NUREG-2191, Section XI.M30, “Fuel Oil Chemistry."

Exceptions to NUREG-2191

None.

Enhancements

The Fuel Oil Chemistry AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
2 - Preventive Actions	Create a new implementing procedure for the fire pump diesel storage tanks that include periodic cleaning and volumetric examinations for signs of loss of material.

3 - Parameters Monitored/Inspected 4 - Detection of Aging Effects	Ensure the fuel oil tank inspections procedures perform: • Steps for repairs or volumetric inspections to verify the FOSTs wall thickness if there are signs of corrosion during visual inspections every 10 years. • Steps to perform cleaning and visual inspections of the diesel generator day tanks at least once every 10 years. Include steps for repairs or volumetric inspections to verify the tank wall thickness if there are signs of corrosion. • Steps to perform cleaning and volumetric examinations to verify tank wall thickness of the fire pump diesel storage tanks at least once every 10 years. If there are signs of loss of material of tank wall thickness, include steps for repairs or additional evaluations.
3 - Parameters Monitored/Inspected 5 - Monitoring & Trending	Ensure the fuel oil chemistry procedures are updated as follows: • Testing, monitoring, and trending frequency for biological activity will be updated to at least quarterly.
5 - Monitoring & Trending	Ensure the fuel oil tank inspection procedures include the following features: • Identified degradation is projected until next scheduled inspection, when practical. • Results are evaluated against the acceptance criteria to confirm that the components will maintain the intended functions based on the projected rate of degradation throughout the SPEO.
6 - Acceptance Criteria	Ensure the fuel oil tank inspection procedures include the following acceptance criteria features: • Any visual degradation of the diesel generator day tanks is reported and evaluated by generating a CR. • Thickness measurements of the FOSTs, diesel generator day tanks, and the fire pump diesel storage tanks are evaluated against the design thickness and corrosion allowance. Any degradation identified during volumetric examinations is reported and evaluated using the CAP.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

- Pertinent industry OE –The OE at some plants has included identification of water in the fuel, particulate contamination, and biological fouling. In addition, when a 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 the American Petroleum Institute (API) 653 standard by welding patch plates over the affected area. A review of the HNP OE from 2013 to present identified approximately 20 CRs concerning water contamination of the fuel oil; however, there were no CRs related to corrosion of the FOSTs, fire pump diesel storage tanks, or the diesel generator day tanks or other components exposed to fuel oil.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation and the relevant OE items are as follows.

- In May 2013, an offsite vendor lubricity test results from a diesel fuel oil delivery to the FOSTs as >520 microns which above the required specification. The chemistry team had reviewed the results and recommended that the diesel generators are operable since there was no immediate effect on diesel operation. The fuel oil was mixed and retested, and the results were acceptable.

- In June 2017, a fuel oil delivery for Unit 1 FOSTs was rejected due to excess water found in the fuel oil. The water was discovered during the required pre-offload sampling and analysis. The testing device was checked, and the fuel was retested with results showing unacceptable water contamination. The site rejected the shipment, and the shipment was rescheduled.

- In September 2017, while conducting the Semi-Annual Diesel Fuel Sampling, HNP found that the samples pulled from the bottom level of both Unit 1 fire pump diesel storage tanks contained a significant amount of sediment. The acceptance criteria for water and sediment are stated as less than or equal to 0.05 percent and the acceptance criteria for samples pulled from the bottom level as less than or equal to 0.1 percent. The “A” sample value was 0.4 percent, and the “B” sample value was 0.025 percent. While the “B” sample was within specification, it was deemed an invalid result as keeping the sediment in suspension to transfer the diesel from the sample container into the testing apparatus was difficult. Visually, the “B” sample container had a similar amount of sediment as the “A” sample container. A resample was performed for each by placing the sample directly from the storage tank into the testing apparatus. Due to all the collected sediment being transferred straight to the testing apparatus, the resample results were significantly higher; the “A” resample value was 0.9 percent while the “B” resample value was 0.6 percent. All other tests performed on both fire pump diesel storage tanks were within acceptance criteria. This CR was initiated, and both tanks need to be cleaned or drained. All applicable individuals were notified, and additional samples were obtained and analyzed. The tank was drained and cleaned to remove the sediment and tank was refilled and retested with acceptable results.

- On December 10, 2018, a diesel generator day tank was sampled, and a small amount of water contamination was detected. Following the procedure requirements, the sample was sent for microbe analysis. The results were as follows: Bacterial Activity, Total Count = 250.0 organisms/ml and yeast and molds, Fuel Phase = 316.67 organisms/ml. Since this sample was not collected prior to the procedure revision, it is not known to plant chemistry personnel what the significance of the data is. As a conservative measure, HNP resampled the FOST and diesel generator day tank for microbe analysis. HNP also treated the FOST with microbiocide. The tanks were resampled in January 2019 and the results showed no signs of detectable microbes or any water in the fuel oil.

- The self assessment, performed in September 2019, compared HNP's fuel oil program to the diesel fuel oil program nuclear industry standard process, identified three deficiencies, which were implemented into the current diesel fuel oil program.

  1. SR diesel fuel off-loads will require conductivity to be performed prior to offload. This will be a new additional analysis for diesel fuel off-loads. Technical evaluations (TEs) were assigned to corporate and site chemistry to update corporate and site procedures.

  2. SR diesel fuel off-loads require total particulate count prior to offload. This was added as an additional analysis for offload. A TE was assigned to site chemistry to update procedures.

  3. SR diesel fuel storage tanks require two new baseline analysis. This was a new analysis added to the procedures. This will be performed offsite by a vendor. A TE was assigned to site chemistry to update procedures.

  The baseline tests (item 3) were determined not to be added to the fuel oil chemistry program. A TE was generated from corporate chemistry to each site to ensure the completion of the baseline tests prescribed in the industry standard. The fuel chemistry program was revised in August 2019 to address the deficiencies identified (items 1 and 2) and to align with diesel fuel oil program nuclear industry standard process.

- The semi-annual sampling in September 2019 of the FOST, was tested by an offsite vendor for microbiological contamination. The sampling results return with a bacterial activity of 16.67 organisms per milliliter. The tank was placed on recirculation and microbiocide was added to the tank. The fuel oil was retested, and the analysis was acceptable with no bacterial activity present.

- The NRC conducted an inspection at HNP in June 2020. A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action", was identified because the licensee did not promptly identify and correct the water intrusion in the FOST. As a result, the emergency diesel generator (EDG) was declared unavailable for three days due to the draining and removing of the fuel and water from the FOST, diesel generator day tank, and associated fuel lines. The water intrusion was from a nearby pull box, which flooded the FOST enclosure since the drain lines were clogged. The water entered the fuel through the tank manway cover. Additionally, the water detection system was not functional due to a calibration error. The corrective actions were to repair the water leak, recalibrate the water detection system, clean the drain lines, and drain the fuel water mixture from the system. The system was returned to operable, and the fuel oil sampling was increased for a period of time to ensure the water intrusion was corrected.

- In February 2021, HNP discovered the fire pump diesel storage tank drain valve had a one drop per minute leak from the bonnet area. The leak was repaired, and the fuel oil was retested and was acceptable.

These examples demonstrate that the program activities executed under the Fuel Oil Chemistry AMP, and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The Fuel Oil Chemistry 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.2.3.19 Reactor Vessel Material Surveillance

Program Description

The Reactor Vessel Material Surveillance AMP is an existing AMP that monitors the changes in the fracture toughness of the ferritic reactor vessel beltline materials due to neutron irradiation embrittlement through the periodic testing of material specimens at different intervals, monitors irradiation embrittlement to a neutron fluence level that is greater than the projected peak neutron fluence of interest projected to the end of the SPEO and provides adequate dosimetry monitoring during the SPEO. 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. The AMP uses neutron dosimeters to monitor the neutron fluence of the surveillance capsules and to provide information to benchmark neutron fluence calculations. The use of dosimetry to monitor neutron fluence is in accordance with BWRVIP-321, Revision 1-A. The fluence projection will continue to be based on the capsule dosimetry unless a major change to the core design or management is undertaken in the future. HNP will continue to determine vessel fluences as needed, in accordance with RG 1.190. The AMP provides for testing and evaluation of in-core surveillance capsule tensile and Charpy specimens and evaluation of capsule neutron exposure for the purpose of evaluating the results of operation on RPV beltline material USE and nil-ductility transition temperature (NDTT).

The Reactor Vessel Material Surveillance Program is part of the BWRVIP Integrated Surveillance Program (ISP). HNP is committed to use the ISP as indicated 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 meets the requirements for an ISP in 10CFR50, Appendix H. Thus, the Reactor Vessel Material Surveillance program meets the requirements of 10 CFR 50, Appendix H.

For the SPEO, the Reactor Vessel Material Surveillance AMP is as described by BWRVIP-321, Revision 1-A which 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 as concluded by the NRC. The ISP capsule insertion, withdrawal, testing schedule is as described in section 8 of BWRVIP-321, Revision 1-A. Because the selection of materials to be reconstituted and tested will depend on which BWRs pursue SLR and need additional surveillance data, the BWRVIP will notify the NRC of test plans and the timeline for reporting test results as described in section 10.3.2 of BWRVIP-321, Revision 1-A. There are no specific acceptance criteria that apply to the surveillance data themselves.

The implementation of the ISP is consistent with the latest version of the ISP plan that has received approval by the NRC for the SPEO.

NUREG-2191 Consistency

The Reactor Vessel Material Surveillance AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.M31, Reactor Vessel Material Surveillance.

Exceptions to NUREG-2191

None.

Enhancements

The Reactor Vessel Material Surveillance Program AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
1 - Scope of Program 3 - Parameters Monitored/Inspected 4 - Detection of Aging Effects 5 - Monitoring & Trending	Implement BWRVIP-321 Revision 1-A to maintain compliance with 10 CFR 50, Appendix H during the SPEO.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per site procedure and takes appropriate corrective actions. A search of the INPO OE database was performed and Industry OE relevant to this AMP are as follows:

- In August 2013, a 120-degree surveillance capsule was removed from a BWR during a refueling outage. In accordance with the reporting requirements of 10 CFR 50 Appendix H, the test results of the capsule must be submitted within one year of the date of capsule withdrawal. Due to complications, EPRI/BWRVIP issued a letter to the NRC to inform that the transmittal of the test report would be delayed beyond the one-year reporting requirement. However, there was no formal acceptance that this extension was approved.

  Hatch initiated a technical evaluation in an effort to avoid such occurrences by informing Hatch management and other personnel involved of the scale of this project.

- In September 2014 during the evaluation of a different BWR's pressure temperature curves, it was identified by an engineering consulting firm that the original pre-irradiated Reference Temperature for Nil-Ductility Temperature (RT_{NDT}) for the reactor vessel plate vessel materials may have been non-conservative. The cause for non-conservatism was the analysis for the original reactor vessel plate data did not indicate the sample's orientation. Testing the material in the weak direction will provide more conservative results. This means that the original data could have overestimated the strength of the material. Using more conservative values would define the most limiting material which would impact the reactor vessel's operating limits.

  On November 27, 2017, Hatch submitted to the NRC Hatch Unit 1 Pressure and Temperature Limits Report that concluded no changes were made to the pressure-temperature curves from testing and analysis of the specimen removed during the Unit 1 Spring 2016. The test results and analysis of the specimen removed from Unit 2 has not been submitted to the NRC to date. This submittal to the NRC following this INPO report did not identify any non-conservatism in the results.

- In May 2017, during a refueling outage in vessel inspection at a BWR, a specimen sample holder basket was found detached from the holder rod. There was no impact to the plant but this optional report was initiated due to the rarity of the failure. The cause of the failure appeared to be fatigue which led to ductile tearing caused by the reactor coolant flow across the holder.

  Hatch initiated a technical evaluation that created new inspection points of specimen sample holders during the Unit 1 Spring 2018 and Unit 2 Spring 2021 outages based on this OE.

<u>Plant Specific Operating Experience</u>

A recent HNP OE search was performed for SLR which covers the last 10 years of operation and the relevant OE items are as follows:

- In August 2018, a condition report documents receipt of BWRVIP letter 2018-045, which contains NEI 03-08 "needed" interim RPV surveillance capsule interim inspection and evaluation guidance. This guidance is considered "needed" for all host plant surveillance capsules that are of the lead tube configuration and scheduled to be withdrawn per BWRVIP-86, Revision 1-A. Since this guidance is applicable to Hatch Unit 1 and Unit 2, inspections required by this interim guidance were incorporated into outage inspections per technical evaluation. Inspections were performed on Unit 1 for the only capsule holder left at 120-degrees. A VT-1 was performed per the interim guidance provided in

BWRVIP letter 2018-045 and no indications were identified during the inspections. Inspections were also performed for Unit 2 in the 2019 outage per the interim guidance provided in 2018-045. A condition report written during this outage stated the RPV internals visual examination of the RPV surveillance capsule holders at 30 & 300 degrees identified an indication on the upper left portion of the lead tube where the alignment tubes are located. A corrective action report dispositioned this indication as minor and did not present risks to the structural integrity or the function of the surveillance sample holder. Therefore, this indication was deemed acceptable (as-is) for continued service. However, the condition action report recommended follow-up inspections in accordance with BWRVIP interim guidance for the next two outages. Follow on inspections of this indication during the Hatch Unit 2 refueling outages in 2021 and 2023 did not lead to any indication notification form generated.

- In February 2020, a condition report documented that two program sub-tier documents listed in a table of procedures in an HNP procedure were incorrect. The procedure, "SNC BWR Vessel and Internals Program (HNP)" incorrectly listed procedure numbers as sub-tier documents of procedure "RPV Integrated Surveillance Guideline" in the supporting/implementing procedure column. The correct procedures that should have been listed were two "Reactor Material Irradiation Specimen Surveillance" procedures. Based on a review of the current version of the procedure "RPV Integrated Surveillance Guideline," the correct references to the procedures have been made.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Reactor Vessel Material Surveillance 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 periodically evaluated.

Conclusion

The Reactor Vessel Material Surveillance 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.2.3.20 One-Time Inspection

Program Description

The One-Time Inspection AMP is a new conditioning monitoring AMP that consists of a one-time inspection of selected components to verify: (1) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO; (2) the insignificance of an aging effect; and (3) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action. The One-Time Inspection AMP will manage the aging effects of loss of material due to crevice corrosion, general corrosion, microbiologically-induced corrosion (MIC), and pitting corrosion, cracking due to SCC, loss of heat transfer capability due to fouling, and long-term loss of material due to general corrosion.

The elements of the One-Time Inspection AMP include: (1) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) 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 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 each population or a maximum of 25 components at each unit. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection is included as part of the program documentation. Factors that will be considered when choosing components for inspection are time in service, severity of operating conditions, and OE.

Identification of inspection locations is based on the potential for the aging effect to occur. 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. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance plant-specific procedures including parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria is based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. The need for follow-up examinations is evaluated based on inspection results if age-related degradation is found that could jeopardize an intended function before the end of the SPEO.

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: (1) affect the intended function of an SSC; (2) result in a potential leak; or (3) 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 One-Time Inspection AMP is used to verify the effectiveness of the 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 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 One-Time Inspection AMP addresses potentially long incubation periods for certain aging effects and provides 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 SC. Situations in which additional confirmation is appropriate include: (1) an aging effect is not expected to occur, but the data are insufficient to rule it out with reasonable confidence; or (2) 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 One-Time Inspection AMP includes 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 is selected for inspection as part of the One-Time Inspection AMP.

The inspections will be scheduled 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 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 Selective Leaching AMP (B.2.3.21). The 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 ASME Code Class 1 Small-Bore Piping AMP (B.2.3.22).

NUREG-2191 Consistency

The 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

HNP evaluates industry OE items for applicability per the Operating Experience 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 should be adequate to demonstrate that the program is capable of detecting the presence or noting the absence of aging effects in the components, materials, and environments where one-time inspection is used to confirm system-wide effectiveness of another preventive or mitigative AMP.

Industry OE was reviewed from the SLR SERs. Two main points of interest are:

- Ensuring that the One-Time Inspection AMP is not used for managing aging of systems or components with known age-related degradation issues.
    - The One-Time Inspection AMP will not be used for structures or components subjected to known age-related degradation mechanisms as determined based on a review of plant-specific and industry OE for the prior operating period.
- Ensuring that one-time inspections are completed on steam generator components, as necessary.
    - Because HNP is a BWR, this OE is not applicable to the One-Time Inspection AMP.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- One-time inspections were performed for original LR, but these inspections were focused on systems susceptible to loss of material due to galvanic corrosion. The results did not show any evidence of galvanic corrosion on the in-scope components. Some systems/components such as the treated water system components and systems/component with air or gas internal environments, have had one-time inspections performed, but these are not in scope of the One-Time Inspection AMP. Since there are no applicable sample groups from original LR, no applicable CRs are identified. The One-Time Inspection AMP verifies the effectiveness of the Water Chemistry AMP, the Fuel Oil Chemistry AMP, and the Lubricating Oil Analysis AMP. CRs and plant-specific OE related to those programs are stated in those respective AMPs. As one-time inspections are performed prior to the SPEO, age-related degradation identified by those inspections will be documented in the One-Time Inspection AMP and evaluated in the CAP.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The One-Time Inspection AMP 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.2.3.21 Selective Leaching

Program Description

The Selective Leaching AMP is a new condition monitoring program that has the principal objective to manage the aging effect of loss of material due to selective leaching.

The Selective Leaching AMP includes inspections of components made of gray cast iron, ductile iron, malleable iron, and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc exposed to a raw water, closed-cycle cooling water (CCCW), treated water, or soil environment. For CCCW 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), based on HNP plant-specific OE which has not revealed selective leaching in these environments. For raw 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 at each unit, except for gray cast iron exposed to soil. For the population of gray cast iron piping exposed to soil, a sample of 20 percent of the population with a maximum of 25 components is visually and mechanically inspected at each unit. For each population exposed to raw water or soil with 35 or more susceptible components, two destructive examinations will be performed in each 10-year inspection interval. For each population exposed to raw water or soil 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. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including parameters such as lighting, distance, offset, and surface conditions.

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.

NUREG-2191 Consistency

The Selective Leaching AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M33, “Selective Leaching".

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

Industry OE shows that selective leaching has been detected in components constructed from gray cast iron, ductile iron, malleable iron, brass, bronze, and aluminum bronze. The following OE from NUREG-2191 Section XI.M33 is relevant to HNP:

- 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 sandblasted 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 (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 (ML13122A009).

- 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 (ML16041A090).

- In July 2019, two ruptures occurred in buried gray cast iron piping associated with the fire protection system (ML19294A044). The cause of the ruptures was determined to be long-standing exposure to moist or wet soil, which resulted in external corrosion and subsequent reduction in wall thickness at these locations. A follow-up submittal (ML19310E716) clarified that the aging mechanism was graphitic corrosion (i.e., selective leaching).

- NRC IN 20-04, Operating Experience Regarding Failure of Buried Fire Protection Main Yard Piping, December 17, 2020. NRC IN 20-04 includes discussion on a 2019 failure of a 12-inch cement-lined cast iron fire protection pipe at HNP. This failure was attributed to an overpressure event which exacerbated a preexisting crack in the pipe, not selective leaching.

- In October 2021, a licensee identified graphitic corrosion on the internal surfaces of cross-sectioned malleable iron pipe fittings. The internal environment was close-cycled cooling water (ML22010A129).

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- During a December 2022 self-assessment, it was discovered that a commitment related to selective leaching may have been missed. Request for additional information (RAI) 3.4-9 in 2000 indicates that HNP committed to performing a selective leaching exam on one cast iron and one brass component within the service water systems between 2009 and 2014 for Unit 1 and between 2013 and 2018 for Unit 2. No documentation was found that these inspections were performed. Subsequent to RAI 3.4-9, it was determined the particular components within the inspection population were composed of materials that were not susceptible to selective leaching. Material analysis confirmed the components were actually either carbon steel or stainless steel. Therefore, no inspection was required. The Plant Service Water and RHR Service Water Inspection Program was reviewed and approved per the January 2014 NRC Post-Approval Site Inspection for License Renewal report (ML14027A638) with no issues identified.

- In November 2022, a buried cast iron fire main ruptured. Metallurgical analysis determined that the rupture resulted from localized graphitic corrosion. The metallurgical analysis also indicated that the external coating of the piping was degraded in some places, which allowed corrosive chemicals in the nearby soil most likely from a previous sanitary water leak to contact the base metal and begin graphitic corrosion. The failed piping was replaced. The extent of condition and corrective actions included soil sampling and additional metallurgical analysis of similar fire protection piping. Some level of chlorides were found in the soil samples. The additional metallurgical analysis found significant graphitic corrosion in a separate section of buried fire water piping that had recently ruptured. Long-term corrective actions to improve the reliability of fire main piping are being developed.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Selective Leaching 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 periodically evaluated.

Conclusion

The Selective Leaching 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.2.3.22 ASME Code Class 1 Small-Bore Piping

Program Description

The ASME Code Class 1 Small-Bore Piping AMP is a new condition monitoring AMP for detecting cracking in small-bore, ASME Code Class 1 piping. This AMP augments the existing ASME Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping with a nominal pipe size (NPS) diameter less than 4 inches and greater than or equal to 1 inch. This AMP provides a one-time and periodic volumetric inspection of a sample of 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 there is no need to manage aging-related degradation. The ASME Code Class 1 Small-Bore Piping AMP includes locations that are susceptible to SCC and cracking due to thermal or vibratory fatigue loading.

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.

One-time and periodic inspections to detect cracking in welds and base metal materials will be performed by either volumetric or destructive examination. 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. 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 weld destructively examined equivalent to having volumetrically examined two welds.

Per NUREG-2191, Table XI.M35-1, HNP is a Category A plant with regard to butt welded piping because it has no history of age-related cracking in butt welded piping. HNP is a Category C plant with regard to socket welded piping because it has experienced age-related cracking in socket welded piping. Category A butt weld inspection will be a one-time inspection with a sample size of 3 percent per unit, up to a maximum of 10 welds per unit. Category C socket weld inspection will be periodic with a sample size of 10 percent per unit, up to a maximum of 25 welds per unit. For socket welds, the first examination will be completed within 6 years of the SPEO and subsequent examinations will be completed every 10 years thereafter. Selection of inspection location will employ a methodology to select the most susceptible and risk-significant welds. Based on the results of these inspections, the need for additional inspections or 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 with 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 ASME Code Class 1 Small-Bore Piping AMP will be 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

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

Since cracking or leakage from Class 1 reactor coolant pressure boundary components would be required to be reported to the NRC per 10 CFR 50.73(a)(2), a review of some relevant Licensee Event Reports (LERs) was performed for piping within the scope of the ASME Code Class 1 Small-Bore Piping AMP.

- **Turkey Point** (LER 05000251/2008-003-00): Repair of a reactor coolant pump 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.
- **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 ISI program. Remaining small-bore instrument nozzle safe ends were ultrasonically examined with no further recordable indications.
- **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.
- **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.
- **Peach Bottom** (LER 05000278/2005-003-00): Replacement of a welded joint on an equalizing line for a residual heat removal (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.
- **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.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. No plant-specific OE was identified pertaining to ASME Code Class 1 small-bore piping for the period mentioned above. However, there were three ASME Class 1 small-bore piping leaks between 2005 and 2008 that were caused by either high cycle fatigue (HCF) or IGSCC. All three leaks occurred on unisolable 1-inch stainless steel instrumentation piping associated with the main steam system and were also related to socket welds. HNP socket welds will be examined periodically due to this OE.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The ASME Code Class 1 Small-Bore Piping AMP 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.2.3.23 External Surfaces Monitoring of Mechanical Components

Program Description

The External Surfaces Monitoring of Mechanical Components AMP is new 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. This AMP will also inspect the integrity of coated surfaces as an effective method for managing the effects of corrosion on the metallic surfaces.

Visual inspections will be performed during system inspections and walkdowns. The inspection parameters for metallic components will 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 will be used as an indicator of possible degradation on underlying surfaces of the component. Inspection parameters for elastomeric components will include hardening, discoloration, surface cracking, crazing, scuffing, loss of thickness, exposure of internal reinforcement, and dimensional changes. For elastomers, manual and physical manipulation to detect hardening or loss of strength will be used to augment the visual inspections conducted under this program. Surface examinations or ASME Code Section XI VT-1 examinations (including those inspections conducted on non-ASME Code components) will be conducted to detect cracking of copper alloy components with more than 15% Zn.

ASME Code inspections will be conducted in accordance with the applicable code requirements. Non-ASME Code inspections and tests will follow site procedures that include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings.

Components will be 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 will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

These visual inspections will 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) will also be periodically inspected at a minimum of every 10 years during the SPEO. Sample inspections will be 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) will be 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 minimum 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.

In some instances, thermal insulation (e.g., calcium silicate) has been included in-scope to reduce heat transfer from components because absent the insulation, the thermal effects could affect a function described in 10 CFR 54.4(a). When metallic jacketing has been used, it is acceptable to conduct external visual inspections of the jacketing to detect damage to the jacketing that would permit in-leakage of moisture as long as the jacketing has been installed in accordance with plant-specific procedures that include configuration features such as minimum overlap, location of seams, etc. If plant-specific procedures do not include these features, an alternative methods for detecting moisture/corrosion inside piping insulation (such as thermography, neutron backscatter devices, and moisture meters) will be used for inspecting piping jacketing.

Visual inspection will identify indirect indicators of elastomer 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 for elastomers cover 100 percent of accessible component surfaces.

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 External Surfaces Monitoring of Mechanical Components AMP will 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 will be performed. The External Surfaces Monitoring of Mechanical

Components AMP procedures will provide the basis to establish that the external and internal surface condition and environment are sufficiently similar. These inspections will provide reasonable assurance that the following effects are managed:

(a) Loss of material/cracking of internal surfaces for metallic components
(b) 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 will be performed per site procedures.

The External Surfaces Monitoring of Mechanical Components AMP procedures will define acceptance criteria that are utilized during inspection walkdowns to identify deficiencies in the in-scope component groups. The External Surfaces Monitoring of Mechanical Components AMP procedures will require corrective actions be initiated for deficiencies identified during the walkdowns to ensure that loss of component intended functions does not occur. The External Surfaces Monitoring of Mechanical Components AMP procedures will utilize guidance from the EPRI Technical Reports TR-1007933 “Aging Assessment Field Guide” and EPRI TR-1009743 “Aging Identification and Assessment Checklist, Mechanical 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 a CR will be issued to perform an assessment and document the appropriate actions and recommendations, which may include the adjustment of inspection frequencies. When a CR is generated, the associated corrective action will be documented in accordance with the CAP and the CRs require the determination of probable cause and actions to prevent recurrence for significant conditions adverse to quality.

NUREG-2191 Consistency

The External Surfaces Monitoring of Mechanical Components AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M36, "External Surfaces Monitoring of Mechanical Components."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. An example of this is the following:

- NRC Information Notice 2012-19 summarizes several issues of concern that were identified during post-approval site inspections, including the need for licensees to manage changes to NRC commitments and AMPs incorporated into the UFSAR supplements.

HNP manages changes to NRC commitments and AMPs under the commitments management procedure.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In March 2013, during a system walkdown, it was discovered that a loose pipe support had scraped the coating off of the "A" reactor feed pump suction pipe, and potentially caused erosion to occur on pipe. Maintenance was sent to investigate the piping and determined that there was no damage to the pipe and there was only the scraped off paint.

- In August 2013, during a system walkdown, rust was discovered on the RHR system piping. The affected area was cleaned and coated to mitigate further material degradation.

- In July 2014, during a coatings walkdown in the condenser bay, numerous coating deficiencies were identified. Blistering/bubbling and flaking coatings were identified at multiple location on the Unit 1 main condenser, a segment of piping, and a segment fire protection piping. WOs were issued and the affected areas were cleaned and recoated.

- In February 2015, during a system walkdown, the Unit 2 high pressure coolant injection torus suction piping expansion joint plastic covering was found to be damaged/degraded. This condition did not affect functionality or operation, but a WO was issued to repair the expansion joint at the next opportunity. Since there was no impact to operability, the WO was closed.

- In November 2017, during a system walkdown, numerous components in the Unit 1 and Unit 2 west cableway were found to be corroded or oxidized. These components included baseplates, brackets, conduits, cable trays, and cable tray supports. The corrosion was likely caused by previous water inleakage. This CR was recorded for tracking purposes only.

- In June 2019, surface corrosion and possible through wall leakage was found on the Unit 2 turbine building chiller economizer following the removal of insulation. In May 2020, a follow-up CR was written to request additional inspections to determine the extent of the degraded conditions. A WO was issued to performed additional visual inspection of the economizer and it was determined moisture trapped under the insulation caused complete loss of coatings, leading to surface erosion of the component. Also performed under this WO were examinations to determine vessel wall thickness. It was determined that there were no integrity concerns because the loss of material recorded was nominal. Another follow-up CR was written to request the economizer coatings be repaired. Another WO was issued to clean and recoat the economizer. Currently, the WO has not been completed as it is recorded as low priority since there are no operability concerns related to the degraded coatings.

- In February 2021, during a system walkdown, ducting in the Unit 2 service air compressor room was found to have peeling coating, leaving the metal exposed to the air. This did not impact system operation but WOs were issued to repaint the ducting. Currently these WOs have not been completed as they are recorded as low priority.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The External Surfaces Monitoring of Mechanical Components 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 periodically evaluated.

Conclusion

The External Surfaces Monitoring of Mechanical 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.2.3.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new condition monitoring AMP that will manage 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 materials.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will consist of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, elastomeric components, and other components exposed to potentially aggressive environments. These environments will include air, gas, condensation, diesel exhaust, and any water-filled systems. Aging effects associated with items within the scope of the Open-Cycle Cooling Water AMP, the Closed Treated Water Systems AMP, and the Fire Water System AMP will not be 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 will be identified. The AMP will include visual inspections and when appropriate, surface examinations. For certain materials, such as elastomers, 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 (defined as components having the same material, environment, and aging effect combination) or a maximum of 19 components per population will be inspected at each unit.

For HNP (two-unit site), where the sample size will not be based on the percentage of the population, a reduction in the total number of inspections to 19 components inspected per unit is acceptable. In order to justify 19 inspections per unit in lieu of 25, the basis for why the operating conditions at each unit are similar enough (e.g., flowrate, chemistry, temperature, excursions) to provide representative inspection results is documented as follows:

- Have power uprates been performed and if so, could more aging have occurred on one unit that has been in the uprate period for a longer time period?
    - Equivalent power uprates have been performed for HNP Units 1 and 2 on the same dates. Therefore, there are no differences in the aging that has occurred between Units 1 and 2 due to different uprate periods.
- Are there any systems which have had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions occurred more frequently?
    - Condition Report keyword searches yield no plant operating experience that indicates long term or repeated out-of-spec water chemistry conditions.
- For raw water systems, is the water source from different sources where one or the other is more susceptible to MIC or other aging effects?
    - There are no operational differences between the Unit 1 and 2 cooling water systems.
- For components exposed to diesel exhaust, have certain diesels operating more frequently and thus exposed to more cool down transients such that more deleterious materials could accumulate?
    - Plant-specific OE does not indicate that any particular diesel has experienced operational issues necessitating changing test or run frequency. Therefore there are no differences between the cooldown transients for the diesel generators.

Based on the above, site operating experience has not indicated a difference in aging effects between the two units for the environment and material combinations managed by this AMP. A representative sample of 19 components per population per Unit are inspected, at a minimum, in each 10-year period during the SPEO.

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 in-scope titanium components. Opportunistic inspections will be performed in each period despite meeting the sampling limit. For certain materials, such as flexible elastomers, 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 components exposed to raw water or waste water, 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 will also be used to manage cracking due to SCC in titanium components exposed to aqueous solutions. Internal coatings of tanks will not be managed by this AMP. This AMP will not be 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 will be conducted if one of the inspections does not meet acceptance criteria. The number of inspections will be increased in accordance with the CAP; however, no fewer than five additional inspections will be 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 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

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. An example of this is the following:

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 systems, structures, and components. The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and NRC expectations. HNP will evaluate 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.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In November 2020, RHRSW piping was found with wall thickness below the minimum requirement. It was determined that this wall thinning was localized and originated on the inside of the pipe. In February 2021, the damaged section of the piping was replaced with 18-inch diameter piping with a wall thickness of 0.5 inches. This was a first time replacement of this piping.

- In February 2021, a valve in the RHR system was found to have internal surface pitting on the valve body. Approximately 30 pits ranging from 3/32 inch to 5/32 inch deep were identified. The plant procedures allowed for a 0.050 inch skim cut of the seating area to repair the pitting, but the pitting was too significant for this repair method. A WO was issued and the valve was disassembled and repaired. Repairs included a <0.050 inch cut to the valve disk and a <0.025 inch cut to the removable seat to create a new seating surface.

- In October 2022, during performance of a license renewal internal inspection, initial examination identified a drain line from a diesel generator cooling water waterbox was clogged. The piping was removed, cleaned of residue, general examination performed, and re-installed.

- In November 2022, during LR internal inspections of an emergency diesel generator air receiver, scaling and corrosion buildup was discovered. The CR was created for tracking purposes only and no WO was issued because the surface conditions identified did not exceed the acceptance criteria established in plant procedures.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components 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 periodically evaluated.

Conclusion

The 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

Program Description

The 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 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 Lubricating Oil Analysis AMP will be conducted by the One-Time Inspection AMP (Section B.2.3.20) on selected components at susceptible locations in oil environments.

The 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 Lubricating Oil Analysis AMP, with one 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 Lubricating Oil Analysis AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
6 - Acceptance Criteria	Clarify the lubricating oil analysis procedures to state that phase-separated water in any amount is not acceptable.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. The following industry OE was identified for lubricating oil aging management:

During testing of the hydrogen seal system at a PWR on March 15, 2023, the total hydrogen seal oil flow was measured at 59.2 gpm (gallon per minute) which was above the expected value of 52.8 gpm. On March 16, following the unit trip, the generator hydrogen pressure decreased from 73 pounds per square inch gauge (psig) to 37 psig. The seal oil strainers were cleaned and the pressure was stabilized at 37 psig.

On May 27, 2023, during the hydrogen seal performance, several parameters were out of specifications. The indication of excessive hydrogen leakage and seal oil flow demand prompted disassembling of the hydrogen seals on the main generator. The inspections showed significant damage to the hydrogen seals due to contaminants in particulates in the hydrogen seal system and lube oil system. The particulates and foreign material were likely a result from the construction phase.

The two systems were flushed until the performance criteria were met. The hydrogen seals were repaired and replaced prior to both systems being put back into service. In addition, the strainer brackets were replaced to ensure no foreign material would enter the system and cause damage. The system was placed back in service and post repair tests were successful. Evaluation of this item shows that monitoring of oil systems is used to identify abnormal conditions.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covers the last 10 years of operation and the relevant OE items are as follows.

- In October of 2014, trace amounts of water were detected in an oil sample from the Unit 2 residual heat removal service water pump motor oil. No other issues with the sample were noted. A functionality determination was performed and determined the function of the pump would not be impacted by the small amount of water detected per engineering evaluation. The engineering evaluation determined the corrosion of components within the oil system was unlikely with water concentrations of less than one percent in the oil. Therefore, there was no need to change the oil as a result of the water contamination.

- In October 2017, a deficient oil condition was discovered in the motor upper reservoir for the Unit 1 condensate pump. Visual analysis from the sight glass and the sample indicated that the oil was contaminated with water. Of the 100 ml sample, approximately 60 ml was water. The 40 ml of oil appeared to be a mixture of water and oil. It was discovered the copper cooling coil used to cool the oil had developed a leak, allowing PSW to leak into the oil reservoir. The pump was removed from service and the copper coil was replaced with a stainless steel coil.

- In June 2022, the motor oil for the Unit 1 PSW pump had a creamy color which was signs of water contamination. An oil sample was taken, and the water content was determined to be below 0.05 percent. All other indicators were acceptable. The oil was deemed acceptable for continued use and functionality of the motor was not impacted.

- The oil sampled in August 2022 from the Unit 2 circulating water pump continued to trend upward in wear particle count. The independent lab confirmed the increased iron levels. As part of the corrective actions, HNP increased the sampling frequency from six months to quarterly. The oil was changed, and flushing was performed at the refueling outage in February 2023. HNP replaced the upper and lower bearing reservoir oil fill/drain/sample carbon steel piping with stainless steel piping in October 2022.

AMP effectiveness will be assessed at least every five years per NEI 14-12. The latest assessment was performed in November 2022 and found no issues.

The Lubricating Oil Analysis 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 periodically evaluated.

Conclusion

The Lubricating Oil Analysis AMP, with one enhancement, 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.2.3.26 Monitoring of Neutron-Absorbing Material Other Than Boraflex

Program Description

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex Aging Management Program 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 five percent sub-criticality margin in the spent fuel pool (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 is used to determine degradation that would challenge the five percent sub-criticality margin. Failure to meet the established criteria will result 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 is 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 five percent sub-criticality margin as contained within the SFP criticality analysis.

In accordance with NUREG-2191, Section XI.M40, the maximum interval between each inspection and between each coupon test will not exceed 10 years, regardless of OE.

NUREG-2191 Consistency

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M40, "Monitoring of Neutron-Absorbing Materials Other Than Boraflex."

Exceptions to NUREG-2191

None.

Enhancements

The Monitoring of Neutron-Absorbing Material Other Than Boraflex AMP will be enhanced as follows for alignment with NUREG-2191.

Element	Enhancement
3 - Parameters Monitored/Inspected	Update the surveillance sample removal and installation procedure to assure EPRI good practices are being used to maintain acceptable chemistry parameters and the corresponding coupon inspection PM tasks specifically document any aluminum oxide layer degradation on the coupon.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the operating experience program and takes appropriate corrective actions. Applicants for SLR reference plant-specific OE and industry experience to provide reasonable assurance that the program is able to detect degradation of the neutron absorbing material in the applicant's SFP. Some of the industry OE that should be included 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 SFP. One instance of this was documented in the Vogtle LR 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 has been reported at Palisades.

(4) The coupon testing program at Kewaunee has observed loss of boron-10 areal density of TETRABOR®.

(5) The coupon testing programs at Calvert Cliffs Unit 1 and Crystal River Unit 3 have observed weight loss of sheet-type Carborundum

Plant Specific Operating Experience

- In May 2014, The results of the latest BORAL® coupon evaluation indicated satisfactory material performance, based on boron-10 areal density and dimensional measurements. However, there was a small area on the edge of the coupon where the aluminum oxide layer eroded off, leaving the clad exposed. This anomaly could be the result of overtightening the capsule around the edges of the coupon or adverse SFP bulk chemistry parameters such as temperature, PH, conductivity, or ion concentrates. Although the cladding was thinning in this small location it did not affect overall coupon performance. The small edge anomaly on the BORAL® coupon was addressed by analyzing chemistry trends to determine if conditions existed that would aggravate aluminum cladding deterioration. The analysis concluded EPRI good practices are being used to maintain acceptable chemistry parameters. The PM documented the condition and it will be noted at the next coupon inspection.

- In October 2015, it was discovered that the coupon inspection procedure and the associated documentation form contained an outdated list of tests performed on the SFP Storage rack sample coupons. This was determined to be an administrative item with procedure content and did not involve scope or performance of the tests. The procedure and form were updated to update the list of tests.

- In January 2020, inspection results on BORAL® sample 18C revealed corrosion pits in a total of 20 places. Some pits breached the cladding and exposed the core. However, no anomalies were visible in the radiograph and no blistering was observed. It was concluded the coupon was in good condition.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex 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 periodically evaluated consistent with the discussion in NUREG 2191, Appendix B.

Conclusion

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP, with enhancements, provides 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.2.3.27 Buried and Underground Piping and Tanks

Program Description

The Buried and Underground Piping and Tanks AMP, previously known as the Underground Pipe and Tanks Monitoring 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 AMP addresses piping and tanks composed of any metallic material that are within the scope of SLR in the emergency diesel generator, fire protection, high pressure coolant injection, PSW, reactor core isolation cooling, residual heat removal, and standby gas treatment systems. There are no buried polymeric components, buried cementitious components, or underground components within the scope of License Renewal that require aging management by the Buried and Underground Piping and Tanks AMP.

This AMP manages aging through preventive, mitigative, inspection, and performance monitoring activities. The Buried and Underground Piping and Tanks AMP includes the following: (a) preventive actions to mitigate degradation (e.g., external coatings or wrappings and quality of backfill), (b) condition monitoring (inspections) (e.g., nondestructive evaluation of pipe or tank wall thicknesses, visual inspections of the external surfaces and coatings/wraps of pipe, and internal tank inspections capable of detecting loss of material on the external surface), (c) performance monitoring activities (e.g., pressure testing of piping, performance monitoring of fire mains) to provide early warning of system leakage, (d) proactive replacement of portions of buried carbon steel piping with stainless steel as part of corrective actions, and (e) continuing to evaluate installation of cathodic protection in targeted locations and installation of targeted cathodic protection in additional locations if determined it would significantly improve plant safety.

Internal inspections may be performed using a method capable of precisely determining piping or tank wall thickness. The method must be capable of detecting both general and pitting corrosion on the external surface of the piping or tank and must be qualified to identify loss of material that does not meet the acceptance criteria. Ultrasonic examinations, in general, satisfy this criterion.

A 2024 soil analysis found that the soil surrounding HNP's in-scope piping was generally mild to moderately corrosive, with certain areas and materials posing a higher risk. HNP will use this information in determining next steps for appropriate preventive actions to effectively manage the aging of its buried and underground piping and tanks. In order to continually monitor potential soil corrosivity, HNP will sample and test the soil excavated for inspections. An evaluation will be performed at least every five years during the SPEO to ensure the soil samples taken during that period are representative of the vicinity in which in-scope components are buried. The results of this soil testing will be used to inform future inspection locations. Additionally, opportunistic inspections of the external surfaces of in-scope buried piping and tanks are performed when the piping or tanks are excavated for any reason.

Site-Specific Inspection Quantities:

Site-Specific Inspection Quantities for buried piping and tanks are required because cathodic protection is not currently installed. In addition, the five buried diesel generator fuel oil storage tanks and the buried plant service water stainless steel piping are not coated. HNP will perform the following number of inspections for each 10-year period, starting in the 10-year period prior to the SPEO:

Stainless Steel Buried Piping

- Two inspections of 10-foot segments

Uncoated Stainless Steel Buried Piping

- Two one-time inspections of 10-foot segments in soil with the highest corrosivity rating will be performed in addition to the first stainless steel inspections prior to the SPEO.

Steel Buried Piping

- The smaller of 10% of the piping length or eleven inspections of 10-foot segments

Copper Alloy Buried Piping

- The smaller of 10% of the piping length or nine inspections of 10-foot segments

Steel Buried Tanks

- One inspection for each of the buried fuel oil storage tanks

Inspection quantities may be reevaluated if HNP determines that appropriate preventive actions can be credited for reduced inspection quantities per NUREG-2191, Section XI.M41.

Site Inspection Locations and Priorities:

Table B.2.3.27-1 identifies material of construction, soil conditions, and plant operating experience for each in-scope system to establish inspection priorities. Characteristics such as coating type (i.e., material type), coating condition, backfill characteristics, soil corrosivity, pipe contents, and pipe function are considered. 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 if the selection criteria are met.

Table B.2.3.27-1: Site Inspection Locations and Priorities

System	Material	Soil Conditions	Previous Inspections/Operating Experience	Inspection Priority[1]
Emergency diesel generator (EDG)	Carbon steel	Moderately corrosive	Piping: Five inspections performed in 2013. All inspections satisfactory. Tanks: All five tanks inspected from 2013 to 2016. All inspections satisfactory.	Piping: CS 4 Tanks: One inspection for each of the buried fuel oil storage tanks
Fire protection	Carbon steel	Moderately to appreciably corrosive	No adverse OE identified.	CS 6
Fire protection	Copper alloy	Unknown	No adverse OE identified.	CA 1
Fire protection	Ductile iron	Moderately to appreciably corrosive	No adverse OE identified.	CS 7[2]
Fire protection	Gray cast iron	Mildly to moderately corrosive	System pressure perturbations have led to mechanical failures. These failures are not believed to be related to external corrosion.	CS 5[2]
High pressure coolant injection (HPCI)	Stainless steel	Moderately to severely corrosive	One inspection performed in 2010. No adverse OE identified.	SS 1
Plant service water (PSW)	Carbon steel	Moderately to appreciably corrosive	39 inspections from 2010 to 2020. Several unsatisfactory results due to both internal and external degradation.	CS 2

System	Material	Soil Conditions	Previous Inspections/Operating Experience	Inspection Priority[1]
Plant service water (PSW)	Stainless steel (uncoated)	Moderately to severely corrosive	No previous inspections or OE identified. Uncoated stainless steel PSW piping was installed in 2014.	USS 1[3]
Reactor core isolation cooling (RCIC)	Stainless steel	Moderately to severely corrosive	Four inspections from 2010 to 2013. No adverse OE identified.	SS 2
Residual heat removal (RHR)	Carbon steel	Moderately to appreciably corrosive	17 inspections from 2010 to 2021. Several unsatisfactory results, mostly related to internal corrosion. Through wall leak in 2020.	CS 1
Standby gas treatment (SBGT)	Carbon steel	Moderately to appreciably corrosive	Three inspections from 2010 to 2013. All inspections satisfactory.	CS 3

Table Notes:

1. Inspection priorities are grouped by material type (e.g., CS for carbon steel) and ranked from highest priority (1) to lowest priority (4). The inspection priorities consider previous inspection results, the number of previous inspections, operating experience, system risk ranking, and the use of preventive actions, if applicable. The total number of inspections for each material type shall be consistent with the quantities listed previously.
2. Ductile and gray cast iron are grouped with the steel population.
3. Two one-time inspections of 10-foot segments in soil with the highest corrosivity rating will be performed in addition to the first stainless steel inspections prior to the SPEO. The inspection results will be trended to ensure the components' intended functions are maintained throughout the subsequent period of extended operation based on the projected rate and extent of degradation. Unacceptable results are entered into the site's corrective action program.

This AMP does not provide aging management of selective leaching. The Selective Leaching AMP (B.2.3.21) is applied in addition to this program for applicable materials and environments.

NUREG-2191 Consistency

The Buried and Underground Piping and Tanks AMP, with enhancements, is consistent with two exceptions to the 10 elements of NUREG-2191, Section XI.M41, “Buried and Underground Piping and Tanks."

Exceptions to NUREG-2191

The Buried and Underground Piping and Tanks AMP includes the following exceptions to the NUREG-2191 guidance:

Exception 1. Element 2, Preventive Actions

Cathodic protection is not installed at HNP as recommended in NUREG-2191, Table XI.M41-1.

Exception 2. Element 2, Preventive Actions

The diesel fuel oil storage tanks and a portion of stainless steel PSW piping are not coated as recommended in NUREG-2191, Table XI.M41-1.

Justification for Exception

Justification for Exception 1

The BUPT AMP is an existing program that has performed excavations and inspections in the past. Historical inspection results have led to additional inspections or replacement as documented in the Underground Piping and Tanks (UPT) Asset Management Plan. HNP is proactively replacing portions of buried carbon steel piping with stainless steel as part of corrective actions driven by the existing program. In addition, HNP is employing an industry recognized software to estimate corrosion rates based on soil samples. A 2024 soil analysis found that the soil surrounding HNP's in-scope piping was generally mild to moderately corrosive, with certain areas and materials posing a higher risk. HNP will use this information in determining next steps for appropriate preventive actions to effectively manage the aging of its buried and underground piping and tanks. In order to continually monitor potential soil corrosivity, HNP will sample and test the soil excavated for inspections. An evaluation will be performed at least every five years during the SPEO to ensure the soil samples taken during that period are representative of the vicinity in which in-scope components are buried. The results of this soil testing will be used to inform future inspection locations.

HNP will continue to evaluate installation of cathodic protection in targeted locations and may install targeted cathodic protection in additional locations if determined it would significantly improve plant safety. In addition, any buried carbon steel piping that is not replaced with stainless steel or cathodically protected will be managed by inspecting the smaller of 10% of the piping length or 11 inspections of 10-foot segments. By reducing the population of piping most susceptible to corrosion, establishing expected corrosion rates based on soil conditions, and inspecting the most susceptible piping, HNP will provide reasonable assurance that its buried piping will continue to perform its intended function through the SPEO.

Justification for Exception 2

The diesel fuel oil storage tanks are internally inspected using volumetric methods on a 10-year frequency. Past inspection results of the tanks have been satisfactory with no indication of wall loss greater than 12.5% of the nominal wall thickness. These satisfactory inspection results in addition to continued periodic inspections and installation of cathodic protection provide reasonable assurance that the tanks will continue to perform their intended function through the SPEO.

Soil sampling indicates that the soil conditions at HNP are moderately to severely corrosive for stainless steels. However, the estimated corrosivity for stainless steels is heavily affected by the modeling assumptions used by the vendor. Consequently, the actual soil condition for stainless steel may be less corrosive than indicated by the model. The uncoated stainless steel PSW piping is conservatively considered the highest inspection priority even though its service life is shorter relative to other buried stainless steel in similar soil environments.

Enhancements

The Buried and Underground Piping and Tanks AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
2 - Preventive Actions	Update the Excavation & Earthwork Quality Control procedure to state that new and replacement backfill shall meet the requirements of NACE SP-0169-2007 Section 5.2.3 or NACE RP-0285-2002 Section 3.6. Backfill that is located within 6 inches of the component that meets ASTM D 448-08 size number 67 (size number 10 for polymeric materials) is considered to meet the objectives of NACE SP0169-1 2007 and NACE RP0285-2002. For stainless steel, backfill limits apply only if the component is coated. The use of controlled low-strength materials (flowable backfill) is also acceptable to meet the objectives of NACE SP0169-2007.
2 - Preventive Actions	Update the BUPT implementing procedure to perform soil testing during excavations for inspections. Soil corrosivity will be evaluated using either American Water Works Association C105, “Polyethylene Encasement for Ductile-Iron Pipe Systems,” Table A.1, “Soil Test Evaluation,” or Electric Power Research Institute Report 3002005294, “Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants,” Table 9-4, “Soil Corrosivity Index from BPWORKS.” Additionally, include a requirement to perform an evaluation at least every five years during the SPEO to ensure the soil samples taken during that period are representative of the vicinity in which in-scope components are buried.
2 - Preventive Actions	Install cathodic protection on the diesel fuel oil storage tanks prior to the SPEO. The cathodic protection system installed on the diesel fuel oil storage tanks will be in accordance with NACE SP0169-2007 or NACE RP0285-2002.
2 - Preventive Actions	Update the Asset Management Plan, procedures, and specifications to require that newly installed, buried stainless steel piping is coated in accordance with Table 1 of National Association of Corrosion Engineers (NACE) SP0169-2007 or Section 3.4 of NACE RP0285-2002.
3 - Parameters Monitored/Inspected	Update the BUPT implementing procedure to monitor for crevice corrosion and MIC for copper alloy, steel (including ductile and gray cast iron), and stainless steel components.

3 - Parameters Monitored/Inspected	Update the BUPT implementing procedure to clarify that inspections for cracking due to SCC for stainless steel and steel (in a carbonate-bicarbonate environment) utilize 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 period; 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 fuel oil storage tank inspection and cleaning tasks to align with the 10-year frequency recommended in NUREG-2191.
4 - Detection of Aging Effects	Update the BUPT implementing procedure to specify that visual inspections are supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed.
4 - Detection of Aging Effects	Update the Underground Piping and Tanks Asset Management Plan to include the plant specific inspection quantities for SLR.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. Industry OE shows that buried and underground piping and tanks are subject to corrosion. Corrosion of buried oil, gas, and hazardous materials pipelines have been adequately managed through a combination of inspections and mitigative techniques, such as those prescribed in NACE SP0169-2007 and NACE RP0285-2002. The following industry OE is identified in NUREG-2191:

- 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 (ML093160004).
- In August 2009, a leak was discovered in a portion of buried aluminum pipe where it passed through a concrete wall. The piping is in the condensate transfer system. The failure was caused by vibration of the pipe within its steel support system. This vibration led to coating failure and eventual galvanic corrosion between the aluminum pipe and the steel supports (ML093160004).
- In April 2010, while performing inspections as part of its buried pipe program, a licensee discovered that major portions of the auxiliary feedwater piping were substantially degraded. The licensee’s cause determination attributes the cause of the corrosion to the failure to properly coat the piping “as specified” during original construction. The

affected piping was replaced during the next refueling outage (ML103000405).

- In November 2013, minor weepage was noted in a 10-inch service water supply line to the emergency diesel generators while performing a modification to a main transformer moat. Coating degradation was noted at approximately 10 locations along the exposed piping. The leaking and unacceptable portions of the degraded pipe were clamped and recoated until a permanent replacement could be implemented (ML13329A422).

The BUPT AMP, with enhancements, is informed by the industry OE items above.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Per NUREG-2191, since cathodic protection is not provided at HNP, this search includes components that are not in-scope for LR if, when compared to in-scope piping, they are of similar materials and coating systems and are buried in a similar soil environment. Relevant OE items are as follows:

- In August 2014, during an inspection for the underground pipe and tanks monitoring program, external pitting corrosion was identified on a 30-inch radwaste discharge pipe resulting in the measured pipe wall being below the acceptable minimum wall calculation. The pitting appeared to be caused by corrosion due to coatings failure. Pitting corrosion was also identified on a separate leg of the 30-inch radwaste discharge piping in a second excavation. The pitting identified in the second excavation did not result in the measured pipe wall being bellow the acceptable minimum wall calculation. The identified pitting was repaired. This piping is not within the scope of SLR.

- In 2015, the 2Y52A001C diesel fuel oil storage tank was cleaned and inspected using the guidance in API Standard 1631. Seventy-one spot UT readings were obtained using a 3ft x 3ft grid and another 24 random readings were taken within the vessel for a total of 95 readings. All measurements were within 12.5 percent of the nominal wall thickness (0.500 inches) with the lowest at 0.468 inches.

- In 2016, the 1R43A002B and 1R43A002C diesel fuel oil storage tanks were cleaned and inspected using the guidance in API Standard 1631. Eighty-five spot UT readings were obtained using a 3ft x 3ft grid and another 25 random readings were taken within each vessel for a total of 110 readings per tank. All measurements were within 12.5 percent of the nominal wall thickness (0.500 inches) with the lowest at 0.462 inches for tank 1R43A002B and 0.458 inches for tank 1R43A002C.

- In 2016, the 2Y52A001A diesel fuel oil storage tank was cleaned and inspected using the guidance in API Standard 1631. Eighty-five spot UT readings were obtained using a 3ft x 3ft grid and another 25 random readings were taken within the vessel for a total of 110 readings. All measurements were within 12.5 percent of the nominal wall thickness (0.500 inches) with the lowest at 0.468 inches.

- In February 2019, a condition report was generated that identified an area of concern related to the number of buried fire protection system piping leaks at HNP. The plant response to this condition report states that system pressure perturbations led to an overpressure event that caused the recent failure. Because of the brittle nature of cast iron piping, system pressure perturbations caused by improper pump starts can lead to piping failures. The evaluation of this OE does not identify external corrosion as a cause of the fire protection piping failures. Corrective actions included replacement of the fire pump engine controllers to prevent simultaneous pump start.

- In 2019, a corrective action report was generated to document the actions taken to address leaks in buried carbon steel piping in the vicinity of the Unit 1 and 2 condensate storage tank (CST) enclosures. Four events were identified related to CST piping leaks between 2007 and 2019 that were attributed to external corrosion or degradation at the carbon steel to concrete interface. Long-term asset management items are tracking the replacement of buried carbon steel piping in the vicinity of the CST with stainless steel piping. A 2024 design change replaced all in-scope buried carbon steel piping that connects to the Unit 1 CST. The replacement piping is wrapped/coated type 304 stainless steel. The equivalent Unit 2 piping is planned to be replaced in 2025.

- In September 2020, the Unit 1, Division 1 RHRSW buried pipe developed a through wall leak due to external pitting. This external pitting corrosion was caused by the degradation of the pipe tape coating from foreign material present in the sand backfill during construction. Progressively over time, the pipe vibration from the process flow and the foreign material in the sand backfill caused the degradation to the pipe coating. A visual inspection of exposed piping in the excavated area identified localized coating damage on U1 PSW, U2 PSW, U2 RHRSW, U2 radwaste dilution line (abandoned in place), and U2 blowdown piping. Based on a review of CR history performed at the time of this event, the extent of condition was determined to be bounded to the immediate excavated area. The failed U1, Division 1 RHRSW piping was replaced. Inspection and coatings repair of the other exposed piping was also completed.

- In 2022, a vendor performed a review of the buried asset program. The report includes information on 115 inspections performed from 2008 to 2021 on systems within the scope of the NEI 09-14 program. Of the systems within the scope of SLR, RHR and PSW were the only systems with adverse inspection results. Due to these results, RHR and PSW will be prioritized for inspection.

- In 2024, a vendor performed soil analysis for buried piping asset management. The analysis included soil sample data from 2010, 2012, 2023, and 2024. The analysis found that the soil surrounding HNP's in-scope piping was generally mild to moderately corrosive, with certain areas and materials posing a higher risk. The results of this analysis are included in and used to inform Table B.2.3.27-1: Site Inspection Locations and Priorities.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Buried and Underground Piping and Tanks 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 periodically evaluated.

Conclusion

The Buried and Underground Piping and Tanks 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.2.3.28 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks 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 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, waste water, and sodium pentaborate solution 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 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, fuel oil, lubricating oil, air or condensation environment at HNP. The 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 Fire Water System (B.2.3.16) AMP.

The 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 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).
- 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 (i.e., coatings specialist) 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. HNP 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 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. 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 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 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.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows.

- In July 2014, when working on the LR inspection of an accumulator, it was discovered the fleet coatings procedure failed to define inspector qualifications for non-service level 1 coatings. The assumption had been made that any knowledgeable person could perform the LR non-service level 1 exams, and any degraded areas identified could then be examined by a qualified coatings inspector. The procedure was revised to better define qualifications.

- In September 2018, visual inspection of a safety-related lubricating oil cooler revealed a uniform indentation approximately 3 inches in diameter on the inlet tubesheet face. Engineering determined the indentation was caused by a tube-to-tube sheet joint weld repair. The Plastocor coating was not restored when the repair was made. No significant corrosion was observed on the bare tubesheet. Lube oil samples were taken to inspect for water in the lube oil. Samples indicated that there was no leakage of the tube-to-tubesheet joint. Eddy current results were satisfactory and no pluggable indications were identified from the 2018 inspection. The recommendation was made to repair at the next opportunity. Subsequent inspection, performed in October 2022, documented chipping of the coating about the size of a credit card, and recommended repairing to prevent further chipping. The coating was repaired on the lube oil cooler to protect the tubes and tubesheet and to prevent further chipping.

- In February 2020, a SR heat exchanger was inspected. The protective coating on the inside of the inlet and outlet channels was observed chipping in various locations where nodules were observed. Failure of the protective coating on the inlet cover plate around the divider plate sealing area was further documented in February 2022. During that maintenance window, both heat exchanger cover plates were replaced with new plates, the divider plate was weld repaired and machined to specification, and the coating on the divider plate was repaired.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The 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

Program Description

The ASME Section XI, Subsection IWE AMP is an existing AMP. This AMP requires visual examinations of the accessible surfaces (base metal and welds) of the drywell, torus, vent headers, penetrations, airlocks, manways and associated integral attachments. The program also requires examination of pressure retaining bolting and moisture barriers.

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. 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 steel containment drywell shell, the drywell air gap and sand pocket drain line outlets are monitored during each refueling outage, when the refueling cavity is flooded, to ensure that the lines are functional and no corrosion mechanisms exist.

Examinations of Class MC pressure-retaining components that detect material loss in a local area exceeding 10 percent of the nominal wall thickness, or material loss in a local area projected to exceed 10 percent of the nominal wall thickness prior to the next examination, are documented in accordance with IWE-3520. Such local areas shall be accepted by engineering evaluation or corrected by repair/replacement activities in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

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 Protective Coating Monitoring and Maintenance AMP (Section 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. Non-coated surfaces are visually examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents and other signs of surface irregularities while coated areas are visually examined for evidence of flaking, blistering, peeling, discoloration and other signs of distress. Pressure-retaining bolting is examined for defects which may cause the bolted connection to violate either containment leak-tightness or structural integrity. Moisture barriers are examined for evidence of wear, damage, erosion, tears, surface cracks, or other defects which may violate the leak-tight integrity.

Supplemental monitoring is also performed to detect cracking for specific pressure-retaining components subject to cyclic loading that have no CLB fatigue analysis; and if triggered by plant-specific operating experience, a one-time supplemental volumetric examination by sampling randomly selected as well as focused locations susceptible to loss of thickness due to corrosion of containment shell that is 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 percent of nominal plate thickness) that is determined to originate from the inaccessible side. Guidance provided in EPRI TR–107514 will be considered when establishing a sampling plan. This sampling is conducted to demonstrate, with 95 percent confidence, that 95 percent of the accessible portion of the metal shell is not experiencing greater than 10 percent wall loss.

Supplemental one-time surface or enhanced visual examinations will be performed for a representative sample (five per unit) of the stainless steel penetrations or DMWs associated with high-temperature stainless steel piping systems in frequent use to confirm the absence of SCC aging effects.

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 ASME Section XI, Subsection IWE AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.S1, "ASME Section XI, Subsection IWE."

Exceptions to NUREG-2191

None.

Enhancements

The ASME Section XI, Subsection IWE AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than the last refueling outage prior to the SPEO, or no later than 6 months prior to the SPEO (i.e., Unit 1: 02/06/2034; Unit 2: 12/13/2037).

Element	Enhancement
2 - Preventive Actions	Specify the preventive actions for storage, lubricants, and SCC 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/Inspected	Monitor accessible portions of high-temperature (temperatures above 140°F) drywell piping penetrations that are not pressurized during local leak rate testing and have no CLB fatigue analysis to detect cracking.
4 - Detection of Aging Effects	Perform supplemental one-time surface or enhanced visual examinations comprising a representative sample (five per unit) of the stainless steel penetrations or DMWs associated with high-temperature (temperatures above 140°F) stainless steel piping systems in frequent use to confirm the absence of SCC aging effects.
4 - Detection of Aging Effects	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 percent of nominal plate thickness) that is determined to originate from the inaccessible side. Guidance provided in EPRI TR–107514 will be considered when establishing a sampling plan. This sampling is conducted to demonstrate, with 95 percent confidence, that 95 percent of the accessible portion of the metal shell is not experiencing greater than 10 percent 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 incrementing sample size during the current outage by one additional penetration at a time from the uninspected population of stainless steel penetrations or DMWs associated with high-temperature (greater than 140°F) stainless steel piping systems in frequent use until cracking is no longer detected. Periodic inspection of subject penetrations with DMWs for cracking will be added to the ASME Section XI, Subsection IWE AMP if necessary, depending on the inspection results.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per relevant site procedures and takes appropriate corrective actions.

- 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. HNP responded to the NRC regarding this industry OE in 1987 stating that HNP Units 1 and 2 containments were designed with multiple drain and leak detection systems to assure that water does not enter and remain in the air gap between the drywell and the surrounding concrete or in the sand cushion. The drain lines (including the seal rupture drain lines) are all of welded construction and embedded in concrete. A bellows has been installed between the concrete and the reactor well to provide a seal and to accommodate any possible differential movement between the concrete and the drywell shell. To provide reasonable assurance that moisture levels associated with an accelerated corrosion rate do not exist, supplemental visual exams are performed each outage for the drywell air gap and sand cushion drain lines to ensure that the lines are functional and no corrosion mechanisms exist. HNP 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, adequately manage aging effects to ensure no loss of intended function.

- NRC IN 92-20 described instances of two-ply containment bellows cracking for which leak rate testing was inadequate for crack detection, resulting in loss of leak tightness. Based on occurrences of transgranular SCC, NUREG-1611 recommends augmented examination of the surfaces of two-ply bellow bodies using qualified enhanced techniques so that cracking can be detected. HNP utilizes bellows assemblies similar to those described in IN 92-20. Following receipt of IN 92-20, a sample of three bellows was selected for augmented testing at the next outage to evaluate the adequacy of the local leak rate testing (LLRT) methods and procedures. A plate was welded inside containment to test the bellows in the proper direction. The tests confirmed that the LLRT testing methods and procedures were acceptable. Visual inspections, performed prior to testing, provide assurance that the bellows are in an acceptable condition for testing. Some of the two-ply bellows assemblies on Unit 2 have been replaced because of bellows leakage detected during LLRT. The bellows leakage was caused by the inadvertent exposure of the bellows to chlorides during maintenance activities. Attachments were added to the HNP Primary Containment Integrated Leakage Rate Test (ILRT) procedures. These attachments contain all penetration bellows which are inspected when pressurized for an ILRT which serves to periodically test the bellows in a fashion that ensures their integrity. When inspected during the Unit 1 ILRT in 1993 no leakage was detected. In addition, the correlation of LLRT minimum path leakage and ILRT leakage was very good, indicating that no significant unknown leakage exists. When inspected during the Unit 2 ILRT in 1992 no leakage was initially detected, but when inspected with an ultrasonic gun leakage was detected on three bellows. Plates were then welded on these penetrations during a refueling outage to LLRT them in the proper direction similar to an ILRT. The plates were welded on and a very small amount of leakage was detected. The noted inspection and testing above ensures that the bellows are in good condition and the issue discussed in IN 92-20 does not exist at HNP. Future inspections during each ILRT will ensure continued integrity is maintained.

- 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. This OE was evaluated for HNP in 2006. HNP has spargers installed on the exhaust pipes from the HPCI. Although the sparger was not part of the original design, it was installed prior to startup on both units. These devices will disperse the turbine exhaust steam limiting condensation oscillations and impingement loads imparted to the torus shell. Since both units have spargers installed on the HPCI exhaust line, the issue of Torus cracking due to the condensation oscillations during HPCI operation is not a problem at HNP.

- NRC IN 2011-15 “Steel Containment Degradation and Associated License Renewal Aging Management Issues,” described several incidents of Nuclear Plants having experienced degradation on their steel containments that could impact the aging management of the containment structure during the period of extended operation of a renewed license. The events described have occurred mainly on BWRs Mark I containment. This OE was evaluated for HNP in 2011 concluding that the current site programs and procedures are adequately managing the integrity of the containment of both units and no procedure or process revisions are required in response to this 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 that some utilities were experiencing degradation of floor weld leak-chase channel systems of metal containments and metal liners of concrete containments. This degradation has the possibility of affecting the leak-tightness and aging management of containment structures. In addition, it was also identified for each of the utilities discussed in the IN, that no program was in place to examine the leak chase test connections. This OE was evaluated for HNP in 2014. As summarized in the IN response, HNP does not have leak chase channels attached to its containment vessel, and thus does not have these leak chase test connections.

- 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. The existing Code examinations and other activities related to moisture barriers at HNP are sufficient to guard against undetected corrosion noted in this industry OE.

<u>Plant Specific Operating Experience</u>

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In 2019 a self-assessment was conducted prior to the Unit 1 refueling outage (1R29). The assessment reviewed the HNP ISI Program, with a focus on outage procedures and readiness. Additionally, the assessment reviewed recent trending information related to ISI specific, NRC Violations in order to determine if the site had any vulnerabilities based on the recent OE. There were no deficiencies identified related to the IWE Program.

- The ASME Section XI ISI Program Owner's Activity Reports (OAR) for the 2022 HNP Unit 1 refueling outage (1R30) and 2021 Hatch Unit 2 refueling outage (2R26) did not identify any flaws or relevant conditions that required evaluation for continued service nor any repair/replacement activities required for continued service related to the IWE program. The reports were for the second period of the 5th ISI Interval (Interval 5, Period 2).

- In February 2022 during the underwater torus inspections, three isolated areas of corrosion were identified in the Unit 1 torus. All three had metal loss that met the criteria established by HNP for reporting the condition to engineering. Following a review by engineering, it was determined that the coatings must be repaired prior to startup. The coating repairs were completed as required during the refueling outage.

- In February 2022 during the venting assembly and suppression chamber surfaces visual Inspection, corrosion was identified in the Unit 1 torus. An engineering evaluation concluded that it was acceptable to leave the degraded conditions "as-is" until they can be repaired. The repairs were completed in February 2024 during the Unit 1 refueling outage (1R31).

- In 2022 a fleet audit of engineering was performed which included activities related to the AMPs and the IWE program. All negative findings were either editorial in nature or related to the document retention records found in a site procedure. All findings were satisfactorily addressed.

These examples demonstrate that the inspections executed under the ASME Section XI, Subsection IWE AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

AMP effectiveness will be assessed at least every five years per NEI 14-12. An effectiveness review was performed in 2023 for the ASME Section XI ISI AMP (including Subsection IWE) which concluded that the ISI program is effective and LR intended functions will continue to be maintained consistent with the CLB for the period of extended operation.

The 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 periodically evaluated.

Conclusion

The ASME Section XI, Subsection IWE AMP, with enhancements, provides 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.2.3.30 ASME Section XI, Subsection IWF

Program Description

The ASME Section XI, Subsection IWF AMP is an existing AMP that manages the effects of loss of material and loss of mechanical function for Class 1, 2, 3, and metal containment component supports. ISI of supports for ASME Class 1, 2, 3, and MC piping and components is part of the ASME Section XI ISI Program. The ISI program is performed in accordance with ASME Code requirements (applicable Edition and Addenda as referenced in the ISI program plan) as modified by 10 CFR 50.55a and approved alternatives. ASME Section XI, Subsection IWF provides the rules and requirements for ISI testing, repair, and replacement of Class 1, 2, 3, and MC component supports. This AMP supplements ASME Code, Section XI, Subsection IWF, which constitutes an existing mandated program applicable to managing the aging of ASME Classes 1, 2, 3, and MC component supports for SLR.

The scope of the program includes support members, structural bolting, high-strength structural bolting, anchor bolts, welds, support anchorage to the building structure, accessible sliding surfaces, constant and variable load spring hangers, guides, and stops. Although the portions of supports that are inaccessible by being encased in concrete, buried underground, or encapsulated by guard pipe are exempt from the examination requirements of IWF-2000, evaluations will be performed for the acceptability of these inaccessible areas when conditions are identified in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

The extent, frequency, and methods of examination are designed to detect, evaluate, or repair age-related degradation before there is a loss of component support intended function. VT-3 inspections are the primary method used to determine the general mechanical and structural condition of components and their associated supports. The AMP monitors and inspects parameters which include corrosion; cracking, deformation; misalignment of supports; missing, detached, or loosened support items; general structural condition of weld joints and weld connections to building structure for loss of integrity; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Accessible areas of sliding or close tolerance machined surfaces are monitored for arc strikes, weld spatter, paint, scoring, roughness, or general corrosion that could prevent or restrict sliding as intended in the design basis of the support. Additionally, a one-time supplemental inspection of an additional five percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports will be performed.

Component support items such as bolting are monitored for loss of integrity due to self-loosening, deformations, and obvious signs of structural degradation including cracks representative of SCC in high-strength bolting. The preventive actions and guidelines emphasize proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting.

Discovery of support deficiencies during regularly scheduled inspections triggers an increase in the inspection scope. Degradation that potentially compromises support function or load capacity is identified for evaluation. ASME Code Section XI, Subsection IWF specifies acceptance criteria and corrective actions. Supports requiring corrective actions are reexamined during the next inspection period. If a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

NUREG-2191 Consistency

The 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 ASME Section XI, Subsection IWF AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
1 - Scope of Program	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	Specify the preventive actions for storage, lubricants, and SCC 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.
4 - Detection of Aging Effects	Perform and document a one-time supplemental inspection of an additional five percent of the sample size specified in Table IWF-2500-1 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 (i.e., based on time in service, aggressive environment, etc.). The one-time inspection will occur within five years prior to entering the SPEO.

4 - Detection of Aging Effects	Specify that, for component supports with high-strength bolting greater than one-inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. 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-inch nominal diameter within the boundaries of IWF-1300 and establish a sample to be 20 percent of the population (for a material / environment combination) up to a maximum of 19 bolts per Unit.
5 - Monitoring & Trending	If a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.
6 - Acceptance Criteria	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.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability and takes appropriate corrective actions.

Degradation of threaded bolting and fasteners has occurred from boric acid corrosion, SCC, and fatigue loading (NRC IEB 82-02, “Degradation of Threaded Fasteners In the Reactor Coolant Pressure Boundary 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). The ASME Section XI, Subsection IWF AMP will (1) specify preventive actions for the storage, lubrication, and SCC potential of high-strength bolts, and (2) perform supplemental volumetric examinations of high-strength bolts to detect cracking in addition to the VT-3 examinations.

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. HNP has a total of eight Bergen constant supports on Unit 1 and eight on Unit 2 which are used to support recirculation system components. There have been no problems with either the constant supports or their beam attachments nor any indication of a potential problem. Due to the size and location of these supports, they are not considered candidates for testing at this time. Also discussions with Bergen engineering did not indicate any problems with the Bergen Constant Supports. These supports are within the scope of the ASME Section XI ISI Program and as such are inspected using the VT-3 examination method for the supports and their attachments.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In March 2013 the fuel pool cooling assist suction piping of the Unit 2 RHR system was found with multiple broken pipe hangers. Initially one hanger was found partially torn off the wall and skewed from its original position. Subsequent walk downs by Engineering and Quality Control (VT-3 examinations) in response to this adverse condition, identified additional damaged supports with one support having both struts completely broken and another having loose bolts. The apparent cause was determined to be water hammer due to voids in the shutdown cooling (SDC) suction piping. Corrective actions were completed to revise procedures to ensure adequate venting is achieved prior to placing SDC in service and repair the damaged pipe hangers.
- In January 2017 while performing seismic restraint inspections for the Unit 1 PSW pumps 1B and 1D, maintenance personnel found a moderate amount of cracking in the coating along with rust, corrosion, and base plate anchor bolt degradation. Engineering determined that the defects caused by the corrosion on the anchor bolts did not adversely affect the structural integrity of the restraints and operability of the pumps was not affected. Coating repairs were performed to address the condition.
- In 2019 a Self-Assessment was conducted to ensure readiness for the Unit 1 refueling outage (1R29) ISI inspections. The assessment reviewed the Hatch ISI Program, with a focus on outage procedures and readiness. Additionally, the assessment reviewed recent trending information related to ISI specific, industry NRC Violations in order to determine if HNP had any vulnerabilities based on the recent OE. There were no deficiencies identified related to the IWF Program.
- The HNP Unit 1 and Unit 2 License Renewal AMP Effectiveness Review performed in 2022 did not identify any gaps or issues with the ASME Section XI, Subsection IWF AMP.
- In 2022 a Fleet Nuclear Oversight Audit of Engineering was performed which included activities related to the AMPs and the IWF Program. All negative findings were either editorial in nature or related to the document retention records found in a site procedure. The document retention issue was addressed.
- The ASME Section XI ISI Program OAR for the 2022 Hatch Unit 1 refueling outage (1R30) identified one relevant condition that required evaluation for continued service and one repair/replacement activity that was required for continued service related to the IWF program. The report was for the second period of the 5th ISI Interval (Interval 5, Period 2, Refueling Outage 2). During the 1R30 ISI examination of the main steam to turbine stop valves pipe support, the wedge anchor nut was found loose which was determined to be acceptable for continued operation without corrective action. The component support was restored to its original design condition during 1R30 prior to startup. Also during 1R30, the beam associated with a main steam pipe support was

found sheared in the web. It was identified that the as-built configuration did not align with the design drawings resulting in a torsional load on the beam which was expected to have contributed to the failure. The beam was weld repaired to match the design drawings during 1R30 prior to startup.

- In February 2024 during a ISI VT-3 exam on a HPCI steam and exhaust system component, a pipe saddle was observed to be detached. No damage to the piping was observed and it was determined that HPCI operability was not impacted by the broken pipe saddle. Corrective actions to install a new pipe saddle were completed.
- In February 2024 while performing a snubber visual exam in the drywell, a nearby snubber in the RHR system was noticed to be unpinned from the support side. Corrective actions to fabricate and install a new pin were completed.

These examples demonstrate that the inspections executed under the ASME Section XI, Subsection IWF AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

AMP effectiveness will be assessed at least every five years per NEI 14-12. An effectiveness review was performed in 2023 for the ASME Section XI ISI AMP (including Subsection IWF) which concluded that the ISI program is effective and LR intended functions will continue to be maintained consistent with the CLB for the period of extended operation.

The 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 periodically evaluated.

Conclusion

The ASME Section XI, Subsection IWF AMP, with enhancements, provides 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.2.3.31 10 CFR Part 50, Appendix J

Program Description

The 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. When leakage rates exceed the acceptance criteria dictated in the HNP Technical Specifications and the associated administrative limits, an evaluation is performed to identify the cause of the unacceptable performance and appropriate corrective actions are taken.

This AMP is implemented in accordance with 10 CFR Part 50, Appendix J, RG 1.163 (Reference 1.6.23), NEI 94-01 (Reference 1.6.24), ANSI/ANS 56.8-2002 (Reference 1.6.25), and is subject to the requirements of 10 CFR Part 54.

As described in 10 CFR Part 50, Appendix J, periodic containment leak rate tests are required to ensure that leakage through the containment pressure-retaining boundary and individual penetration isolation barriers does not exceed allowable leakage rates specified in the HNP Technical Specifications, and the integrity of the containment structure is maintained during its service life. HNP uses Option B, the performance-based approach, to meet the requirements of the containment leak rate test program.

The monitored parameters are leakage rates through the primary containment pressure-retaining boundary and individual penetration isolation barriers. Type A, Type B, and Type C tests are performed at HNP as specified by 10 CFR Part 50, Appendix J, Option B. Type A integrated leak rate tests determine the overall containment integrated leakage rate, at the calculated peak containment internal pressure related to the design basis LOCA. Type B (containment penetration leak rate) tests detect local leaks and measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Type C (containment isolation valve leak rate) tests detect local leaks and measure leakage across containment isolation valves installed in containment penetrations or lines penetrating the containment. Testing and leakage criteria for main steam isolation valves (MSIVs) and the primary containment airlock are specified in accordance with HNP Technical Specifications.

For containment pressure boundary components that are excluded from local leak rate testing, the aging effects associated with those components are managed by the following AMPs:

- ASME Section XI, Subsection IWE for the penetration assemblies (B.2.3.29)
- Water Chemistry for the internal surface of pertinent components (supplemented by the One-Time Inspection AMP) (B.2.3.2)
- One-Time Inspection for the internal surfaces of pertinent components (in conjunction with the Water Chemistry AMP) (B.2.3.20)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Fatigue Monitoring (B.2.2.2)

10 CFR Part 50, Appendix J requires a general visual inspection of the accessible interior and exterior surfaces of the containment structures and components to be performed prior to any Type A test and at periodic intervals between tests based on the performance of the containment system. The 10 CFR Part 50, Appendix J AMP meets this requirement with its implementing procedures. The 10 CFR Part 50, Appendix J AMP visual inspections may be performed in conjunction with the ASME Section XI, Subsection IWE AMP (B.2.3.29) 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. For the hot fluid 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 a one-time volumetric/surface examination of 20 percent of these 24 penetration bellows (i.e., 5 inspections/unit) or enhanced visual examinations conducted by the ASME Section XI, Subsection IWE AMP (B.2.3.29) to detect potential cracking due to cyclic loading.

NUREG-2191 Consistency

The 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

HNP evaluates industry OE items for applicability per the Operating Experience 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 the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem.

The HNP containment design includes bellows on hot fluid piping penetrating the containment. The applicable test procedures were revised to inspect the bellows when pressurized for ILRT. In addition to performing LLRT, inspecting the bellows when pressurized for ILRT ensures continued integrity.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In February 2017, during a local leak rate test, two valves failed to meet the allowable leakage limit. These failures resulted in a failure of the associated vent purge return penetration and resulted in the overall primary containment allowable leakage acceptance criterion to be exceeded. Both valves were repaired and successfully tested in February 2017.

- In February 2020. a LLRT performed on a valve failed. During troubleshooting, the specific valve that was leaking was determined. This valve was rebuilt and restored to service in February 2020. Diagnostic testing of the valve was acceptable.

- In February 2021, a LLRT of the two isolation valves exceeded the allowable limits. During troubleshooting the leakage was confirmed to be past both valves and both valves required repair/replacement. Even though both valves in the penetration exceeded their administrative limits, the condition did not represent a failure of the penetration to maintain primary containment. Both valves were repaired in February 2021. Diagnostic testing of the valves was acceptable.

- In February 2023, during a LLRT of two valves, both individually exceeded the administrative limit. This resulted in a failure of the associated vent purge return penetration. In February 2023, the valves were rebuilt and to alleviate any potential direction-dependent leak characteristics the valves were rotated so that the T-ring seal, the flat face of the valves, face primary containment. Diagnostic testing of the valves was acceptable.

- Appendix J Program Health Report 2023 KPI Summary: HNP Appendix J Program Key Performance Indicator Summary Scorecard was White and decreased from the 2022 score. The action needed to improve to Green was to repair/replace degraded components to maintain leakage below the administrative limits. The repairs were completed in February 2023.
- In August 2024 during a LLRT, two valves failed to meet the allowable leakage limit resulting in a failure to the associated penetration and a loss of primary containment integrity. Due to the repetitive LLRT failures of this penetration, a root cause determination was performed and a corrective action plan developed which is pending implementation. The plan includes a design change that will replace the valves with an improved valve design to minimize the potential for additional LLRT failures.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The 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

Program Description

The Masonry Walls AMP is an existing condition monitoring AMP consisting of inspection activities to detect age-related degradation including shrinkage, separation, gaps, loss of material, and cracking for masonry walls within the scope of SLR. All masonry walls that support SR piping or equipment, or whose failure could prevent a SR system from performing its safety function, are within the scope of the Masonry Walls AMP. The aging effects on masonry walls that are considered fire barriers are also managed by the Fire Protection AMP (B.2.3.15). The aging effects on structural steel elements associated with masonry walls are managed by the Structures Monitoring AMP (B.2.3.33).

The Masonry Walls AMP includes guidance taken from the NRC IEB 80-11, “Masonry Wall Design,” and NRC IN 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11.”

Aging effects identified within the scope of the Masonry Walls AMP are detected by visual inspection of external surfaces prior to the loss of the structure’s or component’s intended function(s). Masonry walls are visually examined by qualified personnel at a frequency not to exceed five years to ensure there is no loss of intended function(s) between inspections and that the evaluation basis established for each masonry wall within the scope of SLR remains valid through the SPEO.

Any adverse condition or observed degradation found during an inspection that is determined to be a potential cause of failure or that indicates changing conditions that may lead to an increased degradation rate is documented. Potential problems found during the inspections are entered into the CAP to determine what, if any, corrective action may be required. Corrective actions generally include continued monitoring, more rigorous inspection, reanalysis, NDE/NDT methods, design enhancements, and repair.

NUREG-2191 Consistency

The Masonry Walls AMP, with an enhancement, is consistent without exception to the 10 elements of NUREG-2191, Section XI.S5, “Masonry Walls.”

Exceptions to NUREG-2191

None.

Enhancements

The Masonry Walls AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
4 - Detection of Aging Effects	The implementing procedure will be enhanced to require inspections for masonry walls to be performed every five years.

Operating Experience

Industry Operating Experience

In May of 1980, IEB 80-11 identified some masonry walls at the Trojan Nuclear Plant that did not have the adequate structural strength to sustain the required piping system support reactions. These deficiencies were attributable to an error in engineering judgment, lack of procedures and procedural detail, and inadequate design criteria. IN 87-67 was issued to inform addressees of lessons learned from NRC inspections of certain activities related to the reevaluation work conducted and plant modifications made in response to IEB 80-11. Deficiencies discovered by various licensees during inspections for IEB 80-11 included improper assumptions, improper classification (safety-related vs nonsafety-related), and a lack of procedural controls.

NUREG-1522 documents the results of a survey sponsored in 1992 to obtain information on the types of distress in the concrete and steel structures and structural components, the type of repairs performed, and the durability of the repairs. Licensees who responded to the survey reported cracking, scaling, and leaching of concrete structures. The degradation was attributed to drying shrinkage, freeze-thaw conditions, and abrasion. The document also describes the results of NRC staff inspections at six plants. The staff observed concrete degradation, corrosion of component support members and anchor bolts, cracks and other deterioration of masonry walls, and groundwater leakage and seepage into underground structures.

HNP response to IEB 80-11 is summarized in Unit 2 FSAR Section 3.8.6.The Masonry Walls AMP was developed using the lessons learned provided in NRC IN 87-67. NUREG-1522 is incorporated into the implementing procedure as a reference to provide lessons learned for industry degradation of civil structures. The Masonry Walls AMP is consistent with industry guidance and experience.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In September 2014, gaps were identified between the top of a CMU wall and the poured concrete ceiling above, and a gap in the grout. The gaps were repaired by using fiberglass when necessary and caulk in June 2015. This repair ensured the CMU wall can meet its original design requirements.
- In October 2017, a masonry block was identified to be chipped. The CMU wall no longer had a full web thickness. The missing portion of the block still afforded a reasonable assurance that the safe shutdown paths would still be protected so the area was considered to have minor degradation. The block's defect was repaired in March 2018.
- In 2015, during the Structural Monitoring Inspections, cracking in the wall of a personnel airlock walkway was observed for trending. The horizontal crack was located at a mortar bed joint. The crack was generally visible the full length of the wall, though of varying widths. In February 2018, other mortar joint cracking, not previously identified, and finer in width, was observed in a stair-step orientation in bed and head joints near the west end of the wall. The condition was classified as acceptable with deficiencies. The wall would perform its design function in this condition. No corrective action was taken.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Masonry Walls 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 periodically evaluated.

Conclusion

The Masonry Walls AMP, with an enhancement, 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

Program Description

The Structures Monitoring AMP is an existing AMP that manages the condition of structures, structural components, and structural supports that are in the scope of LR that are not covered by other structural LR programs. The Structures Monitoring AMP implements the requirements of 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Reference 1.6.6), NRC RG 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Reference 1.6.26), and Nuclear Management and Resources Council 93-01, Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Reference 1.6.27).

The Structures Monitoring AMP provides assurance of the functionality of structures and components which are in the scope of SLR. The program accomplishes this purpose by providing an effective method to monitor structural performance and meet regulatory aging management requirements. The Structures Monitoring AMP consists primarily of periodic visual inspections of plant structures and components for evidence of deterioration or degradation. The Structures Monitoring AMP provides inspection guidelines and walkdown checklists for concrete elements, structural steel, structural bolting, structural features (e.g., caulking, sealants, siding, roofs, etc.), structural supports, and miscellaneous components such as doors and blowout panels. The Structures Monitoring AMP also inspects supports for equipment, piping, conduit, cable trays, HVAC, and instrument components. Though coatings may have been applied to the external surfaces of structural members, no credit is taken for these coatings in the determination of aging effects for the underlying materials. The Structures Monitoring AMP evaluates the condition of the coatings as an indication of the condition of the underlying materials.

The Structures Monitoring AMP manages aging by providing measures for monitoring that detect the effects of aging prior to loss of intended function. Inspections are performed every five years or the next scheduled refueling outages following the five year interval in areas normally inaccessible except during outages. These established frequencies provide assurance that any age-related degradation is detected at an early stage of degradation and that appropriate mitigative actions can be implemented.

The program involves performing walkdowns, conducting inspections, reporting and trending findings, and maintaining inspection data. Visual inspections are used to determine the condition of SSCs within the scope of the Structures Monitoring AMP, unless more rigorous inspections and/or evaluations are deemed necessary. Parameters to be monitored or inspected use guidance based on industry guidelines/criteria such as ACI 349.3R, ACI 201.1R and the American Society for Civil Engineers (ASCE) 11-90 and are provided for each structure type and/or component inspection attribute. For concrete structures, the program includes personnel qualifications and the quantitative acceptance criteria of ACI 349.3R. Results from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of degradation. Trends are documented in the applicable inspection report and condition reports are written for any trend requiring repair or more frequent monitoring.

The program also includes preventive actions to ensure structural bolting integrity, opportunistic inspections for the condition of below-grade concrete and periodic sampling and testing of groundwater chemistry. The frequency of monitoring groundwater chemistry will be at least once every five years during the SPEO. Due to the presence of aggressive groundwater chemistry ($pH < 5.5$), a plant-specific enhancement to manage the concrete aging during SPEO will include a baseline visual inspection and evaluation prior to the SPEO. The inspection will include at a minimum of one location which has experienced aggressive groundwater and consider plant-specific OE. The baseline inspection results will be used to conduct a baseline evaluation that will determine the additional actions that are warranted. Additionally, the baseline evaluation results will set the subsequent inspection requirements and inspection intervals (not to exceed 5 years). Periodic inspections, either focused or opportunistic, and evaluation updates (not to exceed five years) will be performed throughout the SPEO to ensure aging of inaccessible concrete is adequately managed.

NUREG-2191 Consistency

The Structures Monitoring AMP, with enhancements, will be consistent with one exception to the 10 elements of NUREG-2191, Section XI.S6, "Structures Monitoring."

Exceptions to NUREG-2191

The HNP Structures Monitoring AMP includes the following exception to the NUREG-2191 guidance:

Exception 1. Element 4, Detection of Aging Effects

Inspection frequency may exceed five years for areas that are normally inaccessible when the plant is online. These normally inaccessible areas are inspected at the next scheduled refueling outages following the five year interval.

Justification for Exception

Justification for Exception 1

The areas that are normally inaccessible when the plant is online are monitored on an interval that may exceed the five year interval. In general, all structures and components are monitored on an interval not to exceed five years, consistent with GALL-SLR XI.S6. However, if a normally inaccessible area only becomes accessible during an outage in which the five year inspection frequency is exceeded, it is reasonable to exceed the five year frequency depending on safety significance and the condition of the structures and components. Refueling outages are on a 24-month frequency and operating experience supports performing these inspections on a six year frequency.

Enhancements

The Structures Monitoring AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
1 - Scope of Program	Specify that the following component types are contained in the scope: airlocks, ballistic shields, bird screens, louvers, stairs, ladders, handrails, platforms, sliding surfaces, new fuel storage racks, pit boxes, reactor shield wall, refueling water seal assembly, and the RPV pedestal.
2 - Preventive Actions	Specify the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connection publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used for structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts.

2 - Preventive Actions	Clarify that in addition to molybdenum disulfide (MoS_2) lubricants, “other lubricants containing sulfur” will not be used on high-strength bolting.
3 - Parameters Monitored/Inspected	Clarify that in addition to watertight, missile and pressure doors, “doors for shelter and protection” are inspected.
3 - Parameters Monitored/Inspected	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. Considerations may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels.
3 - Parameters Monitored/Inspected	Include surface staining in the list of alkali-silica reaction (ASR) indications.
3 - Parameters Monitored/Inspected 4 - Detection of Aging Effects	Inspect and monitor the loss of material due to pitting or crevice corrosion and cracking in stainless steel and aluminum components.
3 - Parameters Monitored/Inspected 4 - Detection of Aging Effects	Inspect and monitor the loss of mechanical function for sliding surfaces.
3 - Parameters Monitored/Inspected 4 - Detection of Aging Effects	Inspect and monitor below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil which will include the performance of a baseline visual inspection prior to the SPEO at a minimum of one location which has experienced aggressive groundwater. The baseline inspection results will be used to conduct a baseline evaluation that will determine the additional actions (if any) that are warranted.
4 - Detection of Aging Effects	Perform a baseline evaluation prior to the SPEO of the baseline inspection results for below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. The evaluation will consider the baseline inspection results to determine the additional actions (if any) that are warranted. Additional actions may include: enhanced inspection techniques and/or frequency, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. The baseline inspection and evaluation results will set the subsequent inspection requirements and inspection intervals (not to exceed five years) for the SPEO.

4 - Detection of Aging Effects	Inspections for all structures within the scope of the Structures Monitoring AMP to be performed every five years or the next scheduled refueling outages following the five year interval in normally inaccessible areas.
4 - Detection of Aging Effects	Include qualification requirements specified in ACI 349.3R-02 for inspection team members and examiners.
4 - Detection of Aging Effects	Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation of such inaccessible areas.
4 - Detection of Aging Effects	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. Considerations may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels.
5 - Monitoring & Trending	Perform periodic evaluation updates of below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil (not to exceed five years). Updates will be based on OE, periodic inspections, and will consider the opportunistic or focused inspection results during the interval. The periodic evaluation results will update subsequent inspection requirements and inspection intervals (not to exceed five years) for the SPEO as required.
6 - Acceptance Criteria	Include acceptance criteria for the following components and associated aging effects: • Polystyrene blowout panels (loss of material and cracking), • Stainless steel and aluminum components (loss of material - pitting or crevice corrosion and cracking), • Sliding surfaces (loss of mechanical function).

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per relevant site procedures and takes appropriate corrective actions.

- NUREG-1522 documents the results of a survey sponsored in 1992 by the Office of Nuclear Reactor Regulation to obtain information on the types of distress in the concrete and steel SCs, the type of repairs performed, and the durability of the repairs. Licensees who responded to the survey reported cracking, scaling, and leaching of concrete structures. The degradation was attributed to drying shrinkage, freeze-thaw, and abrasion. The NUREG also describes the results of NRC staff inspections at six plants. The staff observed concrete degradation, corrosion of component support members and anchor bolts, cracks and other deterioration of masonry walls, and ground water leakage and seepage into underground structures. IN 2011-20 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 discusses instances of through-wall water leakage from SFPs. NUREG/CR-7111 provides a summary of aging effects of SR concrete structures. Many license renewal applicants, including HNP, have found it necessary to enhance their Structures Monitoring AMPs to ensure that the aging effects of SCs in the scope of 10 CFR 54.4 are adequately managed during the SPEO. An evaluation was performed that showed the aggregate used at HNP is not susceptible to ASR. Additional Structures Monitoring AMP walkdowns performed have not identified indications of ASR at HNP.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- In February 2014 while conducting the structural monitoring program (SMP) inspections for the Unit 1 circulating water flumes, it was discovered that a small surface portion of the concrete has spalled near the top of the sloped section of the original cooling tower discharge flume. Also, near this location minor cracks and erosion of the concrete were observed. It was determined that this dead leg discharge flume could continue to perform its intended function and the concrete was repaired.

- In February 2014 while conducting the SMP inspections in the 500KV high voltage switchyard, it was discovered that a small portion near the base of a support post was rusted through with the remainder of the post appearing to be in good condition. It was determined that the post could continue to meet its design function and the hole was repaired.

- In February 2014 while conducting the SMP inspections in the Unit 1 condenser bay, concrete damage and leaching at a control joint in the ceiling above was discovered. It was determined that the control joint could continue to meet its design function and the control joint was repaired.

- In February 2015 during the Unit 2 refueling outage 23 (2R23) SMP inspections, degraded drywell floor seal material was discovered. The material did not appear to have allowed any moisture intrusion. The seal material was repaired prior to exiting the 2R23 outage.

- In February 2015 during the Unit 2 refueling outage 23 (2R23) SMP inspections adjacent to the south side of the Unit 2 helper tower, it was discovered that the hold down strap for a saddle support was degraded with portions of the strap having significant rust which had delaminated the outer layer of the material. The strap was replaced.

- In February 2015 during the Unit 2 refueling outage 23 (2R23) SMP inspections in the Unit 2 condenser bay off gas pipe chase, very small wall cracks were identified with small amounts of leaching. The condition was evaluated by engineering and determined acceptable for continued service. The wall cracks were categorized as acceptable with deficiencies and are being trended by future Unit 2 SMP inspections.

- In December 2015 while performing pre-start checks on the Unit 2 RHRSW pump, an operator identified loss of coatings and corrosion with loss of metal on the base plate and anchor bolts for a pipe support. This pipe support is located in the PSW piping system that provides cooling water to the RHRSW pumps and also provides support to a strainer monorail hoist. It was determined that the pipe support could perform its intended safety function. The base plate and anchor bolts were replaced.
- In February 2017 during the SMP inspections in the Unit 2 turbine building condenser bay, leaching, efflorescence, and cracks were observed on the east and west walls of the off gas tunnel. The condition did not represent a loss in functionality or capacity of the wall structure. The build-up was scraped and removed to support monitoring and trending of these areas under the SMP which continues.
- In February 2019 during the SMP inspections in the Unit 2 turbine building condensate booster pumps area, corrosion staining was observed on the metal decking supporting a concrete slab. It appeared that the expansion joint above the location was damaged and the concrete had spalled at a few locations along the wall at this joint. There was also evidence of ponding water and moisture staining on the concrete floor above the corroded decking. The condition was evaluated by engineering and determined acceptable for continued service. The condition was classified acceptable with deficiencies.
- SMP inspections were performed for Unit 1 in 2020 and Unit 2 in 2021 . The work scope included inspections, identifying degraded conditions, reporting or trending discoveries, and maintaining inspection data. The following structures and structural components were in the periodic scope of the inspections: reactor building (reactor water clean-up and torus), turbine building (condenser bay), intake structure (roof & exterior walls, trash rakes, pump rooms, suction pit and valve pit), circulating water system (flumes and thrust blocks & supports).
    - For Unit 1, minor deficiencies were identified in the areas observed during the 2020 SMP inspections and fewer new conditions per area were identified than in recent years. These deficiencies were evaluated by engineering and determined acceptable for continued service. No change in the inspection frequency was recommended. Notable changes were observed in the condenser bay, where two newly identified pipe support brackets were observed to have displaced for which CRs were written. Cracking in the ceiling of the condenser bay was also identified but was classified as acceptable. The shotcrete walls of the flumes were noted to have a number of cracks, delaminations, and spalls. These conditions were similar to the findings of the 2018 inspection and the rate of degradation appeared to be steady but has continued between 2018 and 2020. Trending of these conditions will continue to identify any step changes degradation prior to loss of function.
    - For Unit 2, new items identified during the 2021 SMP were generally characterized by isolated conditions such as corroded steel elements, displaced baseplates for pipe supports, and missing connection hardware. No new conditions were identified that would indicate a wide scale structural problem with any of the structures examined and no changes to the inspection frequencies were recommended. Minor change was observed in the Unit 2 condenser bay since the

2011 inspections, indicating a comparatively low rate of deterioration. New conditions identified in the condenser bay included a displaced support and loosened nuts. The 2019 spalled concrete repairs and replaced joint baffles in the Unit 2 flumes were performing well. Two new concrete spalls were identified in the flumes in 2021. The condition of the corroded steel nosing plates and pipe struts had little observed change since the previous inspection. Overall, the rate of development of new conditions in the circulating water system was low.

- In February 2022 during SMP inspections in the Unit 1 condenser bay, corroded steel platform framing was identified at the east drain tank platform. The condition, which was classified as acceptable with deficiencies following engineering evaluation, was first identified in 2018. While some coating repairs were performed prior to 2020, the repairs were fully completed in February 2024.
- In October 2023 degradation of the intake structure grating was identified. As a result, an extent of condition inspection was performed which identified additional sections of grating and a seat angle with varying degrees of corrosion. A work order has been planned to repair the grating.

These examples demonstrate that the scheduled/opportunistic inspections executed under the Structures Monitoring AMP and the follow-on use of the CAP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

AMP effectiveness will be assessed at least every five years per NEI 14-12. An effectiveness review was performed in 2023 for the Structures Monitoring AMP which concluded that the program is effective and LR intended functions will continue to be maintained consistent with the CLB for the period of extended operation.

The Structures 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 periodically evaluated.

Conclusion

The Structures Monitoring AMP, with enhancements, provides 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.2.3.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program Description

The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing condition monitoring AMP that addresses age-related deterioration, degradation due to environmental conditions, and the effects of natural phenomena that may affect water-control structures. The only structure within the scope of the Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is the intake structure. The trash racks, stop logs, traveling screen, and bolting associated with the intake structure are managed by this AMP. Structural steel components associated with the intake structure are managed by the Structure Monitoring AMP (B.2.2.33).

Parameters monitored are in accordance with NRC 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 periodically.

The 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 ISI program for water-control structures. Although HNP is not committed to RG 1.127, this AMP addresses water-control structures, commensurate with the guidance of RG 1.127.

NUREG-2191 Consistency

The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, with enhancements, is 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 Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	**Enhancement**
1 - Scope of Program	The implementing procedure will be enhanced to include stop logs in the scope of the Water-Control Structures Associated with Nuclear Power Plants AMP.
2 - Preventive Actions	Specify the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connection publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used for structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts.
2 - Preventive Actions	The implementing procedure will be enhanced to clarify that in addition to molybdenum disulfide (MoS_2) lubricants, “other lubricants containing sulfur” will not be used on high-strength bolting.
4 - Detection of Aging Effects	The implementing procedure will be enhanced to require inspections for Water-Controlled Structures to be performed every five years.

4 - Detection of Aging Effects	The implementing procedure will be enhanced 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	The implementing procedure will be enhanced to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation of such inaccessible areas.

Operating Experience

Industry Operating Experience

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. NUREG-1522 describes instances and corrective actions of severely degraded steel and concrete components at the intake structure and pump house of coastal plants. Other degradation described include appreciable leakage from the spillway gates, concrete cracking, corrosion of spillway bridge beam seats of a plant dam and cooling canal, and appreciable differential settlement of the outfall structure of another. No loss of intended functions has resulted from these occurrences.

NUREG-1522 is incorporated into the implementing procedure as a reference to provide lessons learned for industry degradation of civil structures. The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is consistent with industry guidance and experience. There is reasonable assurance that implementation of the Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP will be effective in managing the aging of the in-scope structures and structural components through the SPEO.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation. Relevant OE items are as follows:

- During the 2016 Structural Monitoring Inspections in Unit 1 and Unit 2 suction pit of intake structure, several areas of loose, delaminated concrete or spalled concrete were observed. Two loose pieces were removed during the inspection. The concrete degradation was associated with corroded embedded steel plates for equipment supports. The concrete delamination and spalls observed are located along the north wall above grating in Unit 1 and Unit 2. The minor concrete spalling in the suction pit of the intake structure was classified as acceptable until the 2020 Unit 1 Structural Monitoring Inspection when it was classified as acceptable with deficiencies.

- During the 2017 Structural Monitoring Inspections on Unit 1 and Unit 2 roof, cracking was observed in the top surface of the roof slab, located above a concrete column on the centerline of the Intake Structure. The cracks are primarily oriented radially about the column, and was measured typically 0.015” to 0.020” wide. The concrete cracking was classified as acceptable with deficiencies. The areas of cracked concrete do not adversely affect the ability of the intake structure to perform its intended design function. The minor concrete cracking on the roof of the intake structure was documented and trended.

- In 2019, the underwater inspection of the suction pit located at the intake structure was performed. There were no unsatisfactory conditions identified.
- During the 2020 Unit 1 Structural Monitoring Inspections on Unit 1 and Unit 2 suction pit of intake structure, several areas of cracked/delaminated concrete were observed. The concrete degradation was associated with corroded embedded steel plates for equipment supports or corrosion due to shallow cover of reinforcing steel. Areas of delaminated concrete were observed at the following locations from the catwalk: one along the north wall of Unit 1, two along the east wall of Unit 1, and two along the west wall of Unit 2. These surface delaminations were classified as acceptable with deficiencies. The areas of cracked/delaminated concrete do not adversely affect the ability of the intake structure to perform its intended design function. The cracked/delaminated concrete was documented and trended.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The 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

Program Description

The 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 primary containment, on both steel and concrete substrates. Maintenance of Service Level I coatings applied to steel surfaces inside primary 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 emergency core cooling systems (ECCSs) and therefore, a program to manage aging effects on Service Level I coatings for the SPEO is required.

Proper maintenance of protective coatings inside primary containment is essential to the operability of post-accident safety systems that rely on water recycled through the primary 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. American Society for Testing and Materials (ASTM) D 5163-08 (Reference 1.6.28) and endorsed years of the standard in NRC RG 1.54 Revision 3 (Reference 1.6.29) are acceptable and considered consistent with NUREG-2191, Section XI.S8. The Protective Coating Monitoring and Maintenance AMP is a condition monitoring program, with scope that includes Service Level I coatings inside primary containment on both steel and concrete substrates.

The Protective Coating Monitoring and Maintenance AMP provides guidelines for the in-service 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 blistering, cracking, flaking/scaling/peeling/delamination, and rusting. The general visual inspections for coatings in primary containment, including the torus assessment, are performed every refueling outage. 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 primary containment is compared with the total amount of permitted degraded or unqualified coatings to provide reasonable assurance of ECCS operability. Personnel that perform coatings condition assessments are adequately trained in coating inspections by being a Level II Coatings work inspector per ASTM D4537-04 (Reference 1.6.30). Individuals performing follow up inspections are trained in applicable reference standards in accordance with ASTM D5498-12 (Reference 1.6.31).

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 Protective Coating Monitoring and Maintenance AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.S8, “Protective Coating Monitoring and Maintenance.”

Exceptions to NUREG-2191

None.

Enhancements

The Protective Coating Monitoring and Maintenance AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
1 - Scope of Program	The implementing procedure will be enhanced to reference C4 of RG 1.54 Revision 3 for maintenance of Service Level I Coatings.

6 - Acceptance Criteria	The implementing procedure will be enhanced 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.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

- NRC IN 88-82, NRC Bulletin 96-03, NRC GL 04-02, and NRC GL 98-04 describe industry experience pertaining to coatings degradation inside primary containment and the consequential clogging of sump strainers. NRC RG 1.54, Revision 3, was issued in April 2017. 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 and, consequently, an effective means of managing the loss of material due to corrosion of carbon steel structural elements inside primary containment.

The Protective Coating Monitoring and Maintenance AMP's implementing procedure refers to RG 1.54 Revisions 0, 1, and 2; and will be enhanced to reference the guidance of Regulatory Position C4 of RG 1.54 Revision 3.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In 2013, during the Unit 2 refueling outage, the coating inspection of the torus interior vapor space surfaces, multiple items were identified that needed repair. All items identified needed to be prepped and coated. Operability was not impacted by these items. These items were repaired during the next Unit 2 refueling outage in 2015.

- In 2013, during the Unit 2 refueling outage, the coating inspection of the drywell, multiple items were identified that needed repair. All items identified needed to be prepped and coated. Operability was not impacted by these items. These items were repaired during the next Unit 2 refueling outages in 2015 and in 2017.

- In 2016, a protective coating inspection was performed during the Unit 1 refueling outage. Multiple items were identified in the torus proper. These items were repaired during the next Unit 1 refueling outage in 2018.

- In 2016, a protective coating inspection was performed during the Unit 1 refueling outage. Multiple items were identified in the Unit 1 drywell. These items were repaired during the next Unit 1 refueling outage in 2018.

- In 2018, during the Unit 1 refueling outage, the coating inspection of the torus interior surfaces, multiple items were identified which needed to be repaired. These items were repaired during the next Unit 1 refueling outage in 2020.

- In 2020, during the coating inspections for Unit 1 during the refueling outage, multiple areas of degraded coatings were found inside the drywell. The repairs to these areas were performed during the next Unit 1 refueling outage in 2022.
- In 2021, during the coating inspections for Unit 2, during the refueling outage, degraded coatings were found inside of the drywell. The repairs to these areas were performed during the next Unit 2 refueling outage in 2023.

For each inspection the quantity of degraded coatings were found to be within acceptable limits to support ECCS operability.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Protective Coating Monitoring and Maintenance 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 periodically evaluated.

Conclusion

The Protective Coating Monitoring and Maintenance 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.2.3.36 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing condition monitoring AMP. This AMP provides reasonable assurance that the intended functions of accessible 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.

Adverse localized environments are identified through the use of an integrated approach. The approach includes, but is not limited to (1) the review of EQ program radiation levels, temperatures, and moisture levels; (2) recorded information from equipment or plant instrumentation; (3) as-built and field walkdown data (e.g., cable routing data base); (4) a plant spaces scoping and screening methodology; and (5) the review of relevant plant-specific and industry operating experience (OE). This OE includes, but is not limited to the following:

- identification of work practices that have the potential to subject in-scope cable and connection electrical insulation to an adverse localized environment (e.g., equipment thermal insulation removal and restoration)
- corrective actions involving in-scope electrical cable and connection electrical insulation material service life (current operating term)
- previous walkdowns including visual inspection of accessible cable and connection electrical insulation
- environmental monitoring (e.g., long-term periodic environmental monitoring– temperature, radiation, or moisture)

Periodic environmental monitoring consists of a representative number of environmental measurements taken over a sufficient period of time and periodically evaluated to establish the environment for condition monitoring electrical insulation. Plant environmental data can be used in an aging evaluation in different ways, such as by directly applying the plant data in the evaluation or using the plant data to demonstrate conservatism. The methodology employed for monitoring, data collection, and the analysis of localized component environmental data (including temperature, radiation, and moisture) is documented in the record of the analysis. Documentation is provided, as needed, of the applicability of methodologies using data that are collected and evaluated once, or are of limited duration.

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 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, with enhancements, will be 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 Electrical Insulation for Electrical Cables and 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	Enhancement
4 - Detection of Aging Effects	The existing program will be enhanced to include the accessible electrical cables and connections subjected to an ALE and will be visually inspected at least once every 10 years.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience 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 piping 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.

This industry operating experience resulted in the development and need for this program to ensure that insulated cables and connections, located inside and outside of containment, are not exposed to ALEs that subject the insulated cables and connections to environments that exceed their respective 80-year temperature and radiation limits.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In February 2014, during the cable re-termination activities for the recorders in an electrical panel, it was discovered that the power cables to the plant components have badly deteriorated and crumbled as cables were pulled towards the recorders. It appeared that the length of time these cables were exposed to heat inside the panel has caused the cable insulation to be break down (brittle). Moving, pulling the cable around the component showed that the cable insulation easily crack & crumbled. The cables were removed and replaced.

- In March 2015, a power cable was deteriorating due to heat, showing signs of brittleness, with small cracks forming in the wire insulation. It is considered acceptable for continued service, with heat shrink/electrical tape repair per a site procedure. However, the control power cable was replaced in March 2024.
- In November 2019, during adverse localized equipment environment walkdown, a cable was found with a mechanically torn jacket resulting in exposure of the conductor. The condition did not pose any immediate threat to equipment operability or personal safety. A WO was generated and the problem was resolved.
- In November 2019, during adverse localized equipment environment walkdown, cables were found wet with corrosion byproducts on the cable jackets. This degraded condition we identified in several areas where water was leaking through wall penetrations on the cables. In one location it was noted that cables were wrapped in what appeared to be pink colored welding blankets in an attempt to control the water ingression. This application only assisted corrosion by allowing water to collect in the blanket and seep through the fabric creating a wetted cable condition. It was determined the condition at that time did not pose a threat to equipment operability or personnel safety. The leaks were repaired to prevent further water ingression.
- In February 2020, during adverse localized equipment environment walkdown, It was determined that a previously identified ALE from 2011 has degraded since the initial walkdown in 2011. Two conduits connected to (or in proximity of) a valve were initially identified as having brown discoloration. Since then, the conduit appears to be charred, has become darker in color and have also been taped for sealing. The conduits in question were replaced at a later date.
- In February 2021, during adverse localized equipment environment walkdown, two junction boxes showed signs of exposure to high heat and moisture. It was noted that nearby pipes were missing insulation which was determined to have caused the local increased in temperature. The cables in the junction boxes were inspected and determined to be satisfactory.
- In February 2021, during adverse localized equipment environment walkdown, flex conduits leading to the main steam leak detection temperature elements exhibited signs of degradation to continual exposure to heat. The flex conduits were beginning to lose their outer rubberized jacket and the underlying metal was exposed. No damage to the cables were noted and the flex conduits were replaced.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The 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 periodically evaluated.

Conclusion

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements 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.2.3.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits

Program Description

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP, previously known as the Insulated Cables and Connections Program, is an existing condition monitoring AMP. This AMP 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 current 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 insulation resistance causes shorts between conductors and shorts to ground. A reduction in electrical insulation resistance is a concern for all circuits but especially those with sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation circuits, because a reduced insulation resistance 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.

Corrective actions, such as recalibration and circuit troubleshooting, are taken 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 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP, with enhancements, will be 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”.

Exceptions to NUREG-2191

None.

Enhancements

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	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, which are not subject to cable circuit testing. Perform the first periodic review for SLR prior to the SPEO and at least every 10 years thereafter.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

- Peach Bottom SLRA: In 2004, during performance of a main steam line radiation monitor calibration, a high radiation alarm was received several times. The cable connection assembly and splice located in the junction box failed after moving cables and connections in a junction box. Due to an identical replacement cable not being available, an alternate cable assembly was identified and eventually installed.

HNP performs existing calibration and maintenance practices that will help effectively identify and correct any cable and connection issues.

- Surry SLRA: In November 2012, cables were tested for the Unit 2 power range Channel N44 cables. Both the signal and high voltage cables resistance were reading to be out of tolerance. The cables were observed and showed that the mated connector pairs did not have heat shrink tubing or tape and the connectors were immersed in water. The water was determined to be the result of a cavity seal leak. The connectors were cleaned, dried, and reconnected to the connector. This resulted in an even worse resistance reading than before. As a result, the power range Channel N44 detector was replaced with a spare. The new power range Channel N44 detector, with the cables and connectors added, showed that the inner shield low insulation resistance was the reason for the degraded condition for the power range Channel N44 detector.

HNP performs insulation resistance tests, time domain reflectometry tests, and other tests to help determine cable insulation conditions.

- Turkey Point SLRA: During the Spring 2016 refueling outage, range detectors at Turkey Point Unit 4 were declared inoperable multiple times. The cause for source range fluctuations was attributed to cable degradation due to aging, thermal wear, radiation exposure, water, and moisture damage. Both the Unit 3 and Unit 4 cables were being considered for replacement in future outages and the source range detectors were restored to operable status to support plant operations.

HNP monitors for cable degradation due to ALEs that could adversely impact and reduce the insulation resistance of cables and connections in neutron monitoring applications.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In February 2013, condition monitoring cable testing for Intermediate Range Monitor (IRM) F was performed. Time domain reflectometry (TDR), impedance and insulation resistance data was normal. The reverse TDR data revealed noise coupling at the connection of the jumper cable to mineral insulated cable under vessel. The I/V curve indicated a breakdown at 600V which is well above the operating voltage. The IRM F jumper was replaced, and all connectors were cleaned.

- In February 2013, when performing activities under the vessel, it was noted that the cable for IRM "H" was damaged. The cable from the shoot out steel has a split just above the heat shrink where the cable and jumper are connected. A new connector was installed, and heat shrink was placed over the connections.

- In February of 2013, testing of Unit 2 IRM E revealed low insulation resistance data for the shield to ground of the signal cable. An engineering evaluation of the condition, and an operability determination were performed. The cable jacket was previously repaired by taping. A work order removed the damaged section of cable and replaced the connector. The shield to ground resistance remained low. The detector retainer, fiberglass sock and jumper connections were cleaned and the resistance measurement improved. Post maintenance IRM detector testing was satisfactory.

- In September 2013, reverse TDR cable testing for IRM B identified a degraded connection between the subpile jumper and mineral insulated detector cable. The jumper was replaced. The jumper and detector connections were cleaned and post maintenance testing was satisfactory.

- In January 2018, while performing LPRM I/V curves after under vessel maintenance activities, several LPRM’s did not meet the procedure tolerance. Required repairs included replacing SMA connectors and adapter cables, cleaning connectors, reconnecting connectors, and replacing adaptors.

- In February 2018, a Unit 1 main steam line radiation monitor was displaying “BELOW” with a low reading, while the other three monitors were an order of magnitude higher.

This condition caused a channel check failure. Troubleshooting revealed a cut on the high voltage cable through the jacket, shield and mostly through the dielectric. The high voltage cable connector, the signal cable connector and the detector were all replaced. However, the reading was still low. In the main control room, It was then noted that the reading increased when the chassis was slid out of the panel. Touching the signal cable resulted in a change in the reading. The signal cable connector was replaced at the chassis. After the repair, the signal was stable and had increased. The monitor satisfactorily passed a source check.

- In February 2019, while performing LPRM testing after Unit 2 under vessel maintenance activities, six LPRM's did not meet the procedure tolerance. Required repairs included replacing SMA connectors and adapter cables, cleaning connectors, and performing a capacitive discharge test.
- In May 2019, reverse TDR testing of a Unit 1 IRM revealed noise at the preamp cable connector (with preamp bypassed) and under vessel. The under vessel jumper cable was replaced. The jumper and detector connections were cleaned and post maintenance testing was satisfactory.
- In May 2019, reverse TDR testing of a Unit 1 IRM revealed electrical noise coupling at the detector connection under vessel. The outer shield to plant ground resistance was lower than expected, however it was greater than the required minimum resistance. The jumper cable was replaced. The detector connector was replaced, and post maintenance testing was satisfactory.
- In May 2019, reverse TDR testing of a Unit 1 IRM revealed electrical noise coupling at the detector connection under vessel. The jumper cable was replaced. The detector connector was replaced, and post maintenance testing was satisfactory.
- In June 2020, testing of a Unit 1 IRM revealed a short from the cable shield to ground. Testing of a different IRM revealed low DC resistance from the shield to ground. The first IRM retainer and detector connectors were replaced. The second IRM under vessel jumper was replaced and the connections were cleaned. Post maintenance testing was satisfactory.
- In January 2021, pre-outage testing of a Unit 2 IRM indicated the detector was shorted. TDR testing indicated the detector mineral insulated cable was shorted about 14ft above the under-vessel connector. (Total length is approximately 40ft). The IRM was replaced. Post maintenance testing was satisfactory.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification 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 periodically evaluated.

Conclusion

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits 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.2.3.38 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing AMP. The purpose of the 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, pull boxes, 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 pull boxes 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 6 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 pull boxes (if equipped) with remote water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables will be performed at least once every five years.

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 pull boxes or vaults, in preventing cable exposure to significant moisture. If water is found above the acceptance criteria inside a pull box 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 6 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. Inaccessible medium-voltage power cable procedures 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 are 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/pull boxes is managed by the Structures Monitoring (B.2.3.33) AMP. The 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 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 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, with enhancements, will be 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."

Exceptions to NUREG-2191

None.

Enhancements

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be enhanced as follows, for alignment with NUREG-2191.

Element	Enhancement
1 - Scope of Program	Revise implementing documents to define significant moisture as exposure to moisture that lasts more than three (3) days 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 drainage is not considered significant moisture for this AMP.

1 - Scope of Program	Revise implementing documents to include submarine or other cables designed for continuous wetting or submergence as a one-time inspection and test with additional periodic tests and inspections determined by the one-time test/inspection results as well as industry and plant-specific OE.
2 - Preventive Actions	Revise implementing documents to include the inspection of pull boxes equipped with remote water level monitoring and alarms that result in consistent and subsequent pumpout of accumulated water prior to the wetting or submergence of cables at least once every 5 years. Credit for water level monitoring equipment can be taken for devices with continuous self-monitoring features and that generate failure alarms at a central location or the control room. The reliability and methods of ensuring continuous operation of level monitoring devices will be justified and documented.
2 - Preventive Actions	Revise implementing documents to inspect pull boxes for water accumulation after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.
3 - Parameters Monitored/Inspected	The reliability, self-monitoring features, and operation of continuous remote water level and alarm capabilities of such devices, if installed and credited for 5-year inspection intervals, are demonstrated routinely depending on the attributes of the specific equipment used.
4 - Detection of Aging Effects	Revise implementing documents to test medium-voltage power cables within the scope of this program at least once every 6 years.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

Operating experience has shown that inaccessible or underground medium-voltage power cable electrical insulation materials undergo increased degradation either through water tree formation or other aging mechanisms when subjected to significant moisture. Inaccessible or underground medium-voltage cables subjected to significant moisture may result in increased age-related degradation of electrical insulation. Minimizing exposure to significant moisture mitigates the potential for age-related degradation. The HNP program is based on the program description in NUREG-2191 XI.E3A, which in turn is based on industry OE.

By way of background, NRC IN 2002-12, issued March 21, 2002, 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 GL 2007-01, issued February 7, 2007 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. SNC submitted a formal response to NRC GL 2007-01 on May 4, 2007. This documented response stated that HNP had no in-scope cable failures. 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.

The Cable Monitoring Program was initiated to manage the aging effects for cables to assure they can perform their required function and follows the guidance in documents given by INPO, EPRI, and the NRC.

<u>Plant Specific Operating Experience</u>

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows.

- In July 2012, Tan Delta testing on a SR medium-voltage cable, revealed insulation degradation. The cable passed withstand testing at that time and was returned to service. A CR was written to recommend a test frequency of 2 years per EPRI guidelines, and to create a contingency work order, to replace the cable should it fail testing. The cable was replaced in August 2018.

- In October 2015, a yard pull box was found partially buried. According to the plant drawings, the top of the pull box concrete wall is supposed to be out of the ground at least 6”. The ground had been back filled significantly in this area causing this pull box to be surrounded by dirt and gravel, resulting in a damming of water on the cover of the box during rainstorms, thus causing water intrusion into this box which cascades to the next pull box. The wall and lid of the pull box were raised to prevent water intrusion.

- In January 2016, several yard pull boxes were discovered to be missing some or all of the cover hold down bolts. High run time hours were noted on one of the affected pull box sump pumps compared to other pull box sump pumps. The missing bolts were attributed to allowing surface water to enter around the covers. Missing bolts were installed to ensure no missile hazards were present.

- In April 2018, degradation was discovered on a power cable for SR pump motor, during Tan Delta testing by the preventive maintenance program. Test results were unsatisfactory, therefore, a withstand test was performed. The results from the withstand test were inconclusive. Additional inspections were performed per engineering recommendations. Results of the inspections determined the cable needed to be replaced. A new cable was pulled in April 2018.

- In July 2018, a causal analysis was performed to examine the organizational shortfalls in the planning and execution of Tan Delta testing. This was in response to the emergent replacement of medium-voltage power cables as a result of unacceptable Tan Delta testing results. This analysis focused on organizational gaps in risk recognition and challenging, communication, contingency planning, and scheduling of this activity as this test was performed during summer peak. The first corrective action from the analysis was to establish a review in the work planning process for adverse trending of Tan Delta test results. This review would be used to inform the senior leadership team of the risk of testing in the work planning meetings. The second corrective action was for HNP to require a cable replacement to be scheduled once the cable test results show a

"Further Study Criteria," as opposed to increasing the monitoring frequency. Additional enhancements were implemented in the cable monitoring program as a result of this analysis that have strengthened the program's effectiveness.

- In February 2020, degradation was discovered on a medium-voltage SR pump motor power cable during Tan Delta testing. The test frequency was reduced to 2 years, and a contingency work order planned to replace the degraded cable. The cable was replaced in February 2022.

- In September 2020, a review of Hatch pull box performance (from 2018 to 2020) identified several Safety-Related and Non-Safety pull boxes containing sump pumps continually being found at the high-water level or above the limit. A technical evaluation was performed to evaluate the trend. Common failures encountered include blown fuses, debris in the pull box affecting the float switch and motor operations, and drained batteries. The most commonly reported issue was related to debris affecting the operation of the float switch. This causes the pump to continuously run, draining the batteries (which are charged by solar panels), and causes motor and pump reliability issues. The blown fuses were attributed to debris in the pump causing high current draw. Benchmarking results show the float switches are prone to failure after 4-5 years. It also documents a more reliable float switch was approved by engineering, and has been used when replacing float switches since 2016. The maintenance strategy involves installing the new style float switch when a failure occurs.

- In September 2020, Engineering reviewed frequencies of Tan Delta testing for the population of cables within the Cable Monitoring program. The review found discrepancies in the current frequency set in the PM and what they should be based on the most recent Tan Delta test results. Testing frequencies for multiple cables were updated based on the most recent Tan Delta results. The evaluation determined that no Tan Delta testing has been missed and all other in-scope cables comply.

The existing wetted cable commitment scope only includes 4 kV medium-voltage power cables. However, HNP periodically inspects all outdoor electrical duct run pull boxes containing medium-voltage, low voltage, and control cables for water, and water is removed when the level is above the acceptance criteria. Condition reports are generated to document and trend pull boxes with unacceptable levels of water. The cable monitoring program engineer maintains and trends pull box inspection data. All pull boxes with in-scope cables for the first LR have automatic sump pumps. The site OE demonstrates HNP is effectively managing inaccessible cables subject to wetting for medium-voltage power cables.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables 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 periodically evaluated.

Conclusion

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements 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.2.3.39 Electrical Insulation for Inaccessible Instrumentation and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new condition monitoring 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 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, pull boxes, or direct buried installations) I&C cables that are 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 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

When an inaccessible instrument and control cable is exposed to wet, submerged, or other environments for which it was not designed, accelerated age-related degradation of the electrical insulation may occur. The degradation of the cable shield due to water intrusion may introduce electrical ground issues and noise into the circuit.

The risk contribution due to a failure of an inaccessible instrument and control cable may be limited due to system architecture. However, a common environmental aging stressor, such as submergence, represents an aging mechanism that if not anticipated in the design or mitigated in service, could have an adverse effect on the performance of intended functions, or potentially lead to failure of the cable insulation system.

In the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP periodic actions are taken 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 pull boxes/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 pull boxes or vaults, is effective in preventing inaccessible I&C cable exposure to significant moisture.

Inspection of pull boxes (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/pull boxes is managed by the Structures Monitoring (B.2.3.33) AMP. The 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 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.

In addition to inspecting for water accumulation, visual inspections will be performed for I&C cables that are accessible during pull box 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 and 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 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 and underground I&C cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium- or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, construction, 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 recommended in the Electrical Insulation for Inaccessible I&C Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

NUREG-2191 Consistency

The Electrical Insulation for Inaccessible Instrument and Control 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.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

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 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

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 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. SNC submitted a formal response to NRC GL 2007-01, under letter NL-07-0950. This documented response stated that HNP had no in-scope cable failures. 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.

The Cable Management Program at HNP was initiated to manage the aging effects for cables to assure that they can perform their required function and follows the guidance in documents given by INPO, EPRI, and the NRC.

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In October 2015, a yard pull box was found partially buried. According to the plant drawings, the top of the pull box concrete wall is supposed to be out of the ground at least 6”. The ground had been back filled significantly in this area causing this pull box to be surrounded by dirt and gravel, resulting in a damming of water on the cover of the box during rainstorms, thus causing water intrusion into this box which possibly cascades to the next pull box. The issue was resolved by raising the wall and lid of the pullbox to prevent water intrusion.

- In January 2016, several yard pull boxes were discovered to be missing some or all of the cover hold down bolts. High run time hours were noted on one of the affected pull box sump pumps compared to other pull box sump pumps. The missing bolts were attributed to allowing surface water to enter around the covers. The missing bolts were addressed to ensure no missile hazards were present.

- In October 2018, flow monitors exhibited erratic behavior. Troubleshooting revealed standing water inside the one train's transmitter box. Water was found in the flexible conduit containing the instrument cables originating from a higher elevation. Water was also found in the flexible conduit on the opposite train. The conduits were arranged such that a low point was formed, allowing the water to pool. Further investigation revealed moisture in the box at the higher elevation. Moisture was observed on the outside of the flow element inlet moisture shields and the inside edge of the outlet moisture shields. The moisture was removed from the flexible conduits. Weep holes were installed in the flexible conduits. The instruments were reported to be working properly after subsequent calibration.

- In May 2019 multiple CRs were identified for a Unit 1 radiation monitor. The radiation monitor was reported to be intermittently spiking, causing alarms to annunciate multiple times per shift in the main control room. Maintenance troubleshooting identified a cable severely degraded between two pull boxes. It was discovered the existing cable was too degraded to properly splice. New cable was pulled for the circuit. Further review of CRs related to the affected pull boxes revealed multiple instances of excessive water found in one of the pull boxes and multiple CRs written for deficiencies with the automatic sump pump system the same pull box.

- In September 2020, a review of Hatch pull box performance from (2018 to 2020) identified several safety-related and non-safety pull boxes containing sump pumps continually being found at the high-water level or above the limit. A technical evaluation was performed to evaluate the trend. Common failures encountered include blown fuses, debris in the pull box affecting the float switch and motor operations, and drained batteries. The most commonly reported issue was related to debris affecting the operation of the float switch. This causes the pump to continuously run, draining the batteries (which are charged by solar panels), and causes motor and pump reliability issues. The blown fuses were attributed to debris in the pump causing high current draw. Benchmarking results show the float switches are prone to failure after 4-5 years. It also documents a more reliable float switch was approved by engineering and has been used when replacing float switches since 2016. The maintenance strategy involves installing the new style float switch when a failure occurs.

- In February 2021, a ground fault alarm was received in the Unit 2 Control Room for the 125/250 volts-direct current (VDC) system. A ground was identified on two conductors in a control cable. The cable runs in an underground conduit through the Unit 2 switch yard to a 500kV disconnect switch. Two spare conductors in the cable bundle were used to swap with the damaged conductors. A new cable was pulled in February 2023. While replacing the cable, mud and dirt were found in, and removed from, the field junction box.

A self-assessment of the wetted cable AMP was conducted in November 2022. No significant deficiencies were identified as a result of the self-assessment.

HNP periodically inspects all outdoor electrical duct run pull boxes containing medium-voltage, low-voltage, and control cables for water, and water is removed when the level is above the acceptance criteria. Condition reports are generated to document and trend pull boxes with unacceptable levels of water. The cable monitoring program engineer maintains and trends pull box inspection data. All pull boxes with in-scope cables for the first LR have automatic sump pumps. The site OE demonstrates HNP is effectively managing inaccessible cables subject to wetting for medium-voltage power cables and will be able to effectively manage inaccessible instrument and control cables as well.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Electrical Insulation for Inaccessible Instrument and Control 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 periodically evaluated.

Conclusion

The Electrical Insulation for Inaccessible Instrument and Control 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

Program Description

The Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new condition monitoring AMP. The purpose of the 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 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, pull boxes, manholes, or direct buried installations) non-EQ low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of SLR that are potentially exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. 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 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 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 pull boxes/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.

The aging management of the physical structures, including cable support structures of cable vaults/pull boxes, is managed by the 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) 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 pull boxes 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 pull box inspections for jacket surface abnormalities. 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 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.

If required, the cable testing 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, the extent of 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) 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 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."

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 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 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.

Plant Specific Operating Experience

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 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. SNC submitted a formal response to NRC GL 2007-01, under letter NL-07-0950. This documented response stated that HNP had no in-scope cable failures. 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.

The Cable Management Program at HNP was initiated to manage the aging effects for cables to assure that they can perform their required function, and follows the guidance in documents given by INPO, EPRI, and the NRC.

A self-assessment of the wetted cable AMP was conducted in November 2022. No significant deficiencies were identified in the wetted cable AMP as a result of the self-assessment.

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In October 2015, a yard pull box was found partially buried. According to the plant drawings, the top of the pull box concrete wall is supposed to be out of the ground at least 6”. The ground had been back filled significantly in this area causing this pull box to be surrounded by dirt and gravel, resulting in a damming of water on the cover of the box during rainstorms, thus causing water intrusion into this box which possibly cascades to the next pull box. The issue was resolved through the work order process.

- In January 2016, several yard pull boxes were discovered to be missing some or all of the cover hold down bolts. High run time hours were noted on one of the affected pull box sump pumps compared to other pull box sump pumps. The missing bolts were attributed to allowing surface water to enter around the covers. The missing bolts were addressed to ensure no missile hazards were present. A CAP review of the pull box revealed a trend of various pump related issues associated with this pull box.

- In September 2020, a review of Hatch Pull box performance from (2018 to 2020) identified several SR and NSR pull boxes containing sump pumps continually being found at the high-water level or above the limit. A technical evaluation was performed to evaluate the trend. Common failures encountered include blown fuses, debris in the pull box affecting the float switch and motor operations, and drained batteries. The most commonly reported issue was related to debris affecting the operation of the float switch. This causes the pump to continuously run, draining the batteries (which are charged by solar panels), and causes motor and pump reliability issues. The blown fuses were attributed to debris in the pump causing high current draw. Benchmarking results show the float switches are prone to failure after 4-5 years. It also documents a more reliable float switch was approved by engineering, and has been used when replacing float switches since 2016. The maintenance strategy involves installing the new style float switch when a failure occurs.

The existing wetted cable commitment scope only includes medium-voltage (4kV) power cables. However, HNP periodically inspects outdoor electrical duct run pull boxes containing medium-voltage, low-voltage, and control cables for water, and water is removed when the level is above the acceptance criteria. Condition reports are generated to document and trend pull boxes with unacceptable levels of water. The cable monitoring program engineer maintains and trends pull box inspection data. All pull boxes with in-scope cables for the first LR have automatic sump pumps. The site OE demonstrates HNP is effectively managing inaccessible cables subject to wetting for medium-voltage power cables, and OE gained by HNP through these activities will be used to effectively manage inaccessible low-voltage power cable as well.

AMP effectiveness will be assessed at least every five years per NEI 14-12. While this is a new AMP, the wetted cables AMP, which is an existing similar AMP, received a satisfactory effectiveness review in 2023.

The 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 periodically evaluated.

Conclusion

The 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 AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.41 Fuse Holders

Program Description

The Fuse Holder AMP is a new condition monitoring program that ensures the metallic clamp portion of fuse holders inside passive electrical enclosures continue to perform their intended function. The metallic clamp portion of the fuse holder is tested to detect any increased resistance of the connection or fatigue. The electrical insulation material portion of the fuse holder is visually inspected to identify insulation surface anomalies, indicating signs of reduced insulation resistance.

The metallic clamp portion of in-scope fuse holders will be tested using thermography to detect any indication of resistance of the connection due to chemical contamination, corrosion, and oxidation. For fuses within the scope of LR, testing or inspection will be used to identify fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement or vibration. The electrical insulation material portion of in-scope fuse holders will be visually inspected to identify insulation surface anomalies, indicating signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis and photolysis (UV-sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion as indicated by signs of embrittlement, discoloration, cracking, melting, swelling, or surface contamination. The fuse holders located outside of active devices will be visually inspected and tested by thermography.

The fuse holder testing will be performed at least once every ten years. The first test will be completed before the SPEO. The 10-year inspection interval will provide two data points during a 20-year period, which will characterize the degradation rate. The 10-year inspection interval is an adequate period to preclude failures of the fuse holders since experience has shown that aging degradation is a slow process.

Test acceptance criteria will show that fuse holders are free from the unacceptable aging effects of increased resistance of connection or fatigue. The acceptance criteria for thermography testing of the metallic clamp of the fuse holder will be below the maximum allowed temperature for the application, or a low resistance value appropriate for the application is applicable when resistance measurement is used. Fuses holders subject to frequent removal and reinstallation will be inspected for mechanical fatigue. Visual inspection acceptance criteria will show that fuse holders are free from unacceptable electrical insulation surface anomalies indicating signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis and photolysis (UV-sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion as indicated by signs of embrittlement, discoloration, cracking, melting, swelling, or surface contamination.

NUREG-2191 Consistency

The Fuse Holders AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.E5, "Fuse Holders."

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

Industry OE has shown that repetitive removal and reinsertion of fuses during maintenance or surveillance activities can lead to degradation of the fuse holders. Fuse holders, located outside of active equipment, where fuses are removed and replaced frequently for maintenance or surveillance activities, are also included in this AMP to manage these repetitive activities.

HNP evaluates industry OE items for applicability and takes appropriate corrective actions.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operations and the relevant OE items are as follows.

- In April 2016, a fuse holder divider piece came off of the holder. Although the cause of the failure was determined to be a portion of Bakelite which functions as a divider between two adjacent fuses and did not affect the operability of the fuse, the fuse was replaced by maintenance.
- In April 2016, electricians were called to assist Operations to determine the reason for a CO_2 storage tank pressure alarm. After inspection, it was determined that the fuse holder for the control power fuse was loose. The cause of the loosening was indeterminate but maintenance tightened the fuse holder and returned the component to service.
- In October 2016, when attempting to perform a tie-in of a FLEX inverter, the red "Uninterruptible Power Supply (UPS) ON SATIC BYPASS" light failed to illuminate during maintenance as expected. The cause was determined to be a cracked 1A fuse holder. It was determined that an internal end of the holder for the fuse was broken off and laying free against the external housing of the bypass switch in the enclosure. The fuse holder was replaced. In November 2016, the same fuse holder failure was found on the 2B fuse, and the fuse holder was subsequently replaced.
- In August 2021, while restarting the "A" recirculation pump, the recirculation pump discharge valve position indication light extinguished, then re-lit intermittently. Valve position movement was also found to be intermittent. The cause was determined to be a loose fuse in the recirculation pump discharge valve control power circuit. The fuse holder was replaced by maintenance.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Fuse Holders 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 periodically evaluated.

Conclusion

The Fuse Holders 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.2.3.42 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements AMP is a new condition monitoring 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. One-time testing, on a sample basis, will confirm the absence of age-related degradation of cable connections resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation. 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 switchyard connections (>35 kV). Cable connections covered under the EQ program are not included in the scope of this AMP.

A representative sample of cable connections within the scope of SLR are tested on a one-time test basis to confirm the absence of age-related degradation of the cable connection. Initial one-time test findings will document unacceptable conditions or degradation identified and whether they were determined to be age-related thereby requiring subsequent testing on a 10-year basis. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. One-time testing provides additional confirmation to support industry operating experience (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 10-year 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. Otherwise, a technical basis will be given on the method and sample size of components utilized and will be documented as part of this program. The one-time tests 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 is performed 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 Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements AMP, will be consistent to the 10 elements of NUREG-2191, Section XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience 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. HNP’s OE with connection reliability and aging effects should be adequate to demonstrate the AMP effectiveness of GALL-SLR Report AMP XI.E6, “Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” including the program’s capability to detect the presence or noting the absence of aging effects for electrical cable connections.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operation and the relevant OE items are as follows:

- In April 2013, thermography inspection of the U2 main transformers revealed elevated temperatures on five of the six isophase bus ground risers. Peak currents of up to 1031 A and peak temperatures of up to 348°F were documented on these ground risers. In April 2014, industry OE was reviewed and a similar condition was found previously reported at a different site. Engineering reviewed past thermography images to determine if the cause of hot ground risers was similar to the cause at a different site. It was found that on each location with a hot ground riser, there was a single bolt connecting the isophase bus duct enclosure to the structural steel column. The single bolts had elevated temperatures which were similar to their respective ground risers. All bolted connections were cleaned and properly torqued to achieve an adequate ground. After maintenance, thermography revealed the ground riser temperatures to be at or slightly above ambient conditions.

- In March 2014, while performing thermography testing, an anomaly was identified. A terminal block had cabling/connections with temperature levels of 212°F. When compared to the similar component a 112°F delta was noted. The component in one panel was 20°F above ambient whereas the component of concern was 132°F above ambient. Additional anomalies noted between these two strips where both had fuses above ambient temperatures. In another panel, a fuse had temperature of 122°F. Another panel had a fuse that was 137°F and another fuse was 150°F. However, engineering evaluation determined the high temperatures were isolated to the lugs at the terminal block. The insulation was inspected and did not show any signs of degradation. The connection lug on the terminal was tightened approximately half a turn. The temperature of the connection was 90°F during follow-up thermography.

- In April 2018, while performing a scheduled thermography activity, thermal anomalies were observed on electrical connections of two breakers. During analysis, recent images were compared to previous survey images. One of the breaker's electrical connections had a 15°F increase in temperature and a different thermal signature. Previous survey images measured this electrical connection in the 115°F range. On the other breaker, a temperature increase of 6°F from previous inspection was noted on an electrical connection. The observed temperatures did not exceed the procedural threshold, and did not present an immediate problem or threat to the operability of the system. The connections were verified to be properly torqued.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ 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 periodically evaluated.

Conclusion

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ 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.2.3.43 High-Voltage Insulators

Program Description

The High-Voltage Insulators AMP is a new condition monitoring AMP that provides reasonable assurance that the intended functions of high-voltage insulators within the scope of SLR are maintained consistent with the CLB through the SPEO. The High-Voltage Insulator AMP was developed specifically to age manage high-voltage insulators susceptible to aging degradation due to local environmental conditions. This AMP is applicable to different types of high-voltage insulators such as porcelain, toughened glass, and polymer.

The high-voltage insulators AMP will be a condition monitoring program that relies on visual inspections and high-voltage insulator cleaning, and optionally coating, to manage high-voltage insulator aging effects. High-voltage insulator periodic visual inspections are performed to monitor the buildup of contaminants on the insulator surface. The periodic coating or cleaning of high-voltage insulators limits high-voltage insulator surface contamination.

The program includes the inspection of the high-voltage insulators within the scope of this program to identify degradation of high-voltage insulator sub-component parts, namely, insulation and metallic elements. Visual inspection provides reasonable assurance that the applicable aging effects are identified, and high-voltage insulator age degradation is managed. Insulation materials used in high-voltage insulators may degrade more rapidly than expected when installed in an environment conducive to accelerated aging. The insulation and metallic elements of high-voltage insulators are made of porcelain, cement, malleable iron, aluminum, polymer, and galvanized steel. The most common type of high-voltage insulators used throughout switchyards, transmission lines, and power systems are porcelain. However, polymer and toughened glass high-voltage insulators are also found in some installations and are included in this AMP. Polymer high-voltage insulators are typically composed of material such as fiberglass, silicone rubber (SiR), ethylene propylene rubber (EPR), epoxy, silicone gel, sealants, ductile iron, aluminum, aluminum alloys, steel, steel alloys, malleable iron, and galvanized metals. Exposure to air-outdoor can cause degradation and aging effects that can result in reduced insulation resistance due to deposits and surface contamination, reduced insulation resistance due to polymer degradation as well as loss of material caused by wind blowing on transmission conductors, and loss of material due to corrosion, all of which may require aging management. Polymer high-voltage insulators have been shown to have unique failure modes with minimal advance indications. Surface buildup of contamination can be worse for SiR (compared to porcelain insulators) due to absorption by silicone oil, especially in late stages of service life.

The high-voltage insulators within the scope of this program are to be visually inspected at a frequency based on plant-specific operating experience (OE) with the specific type of insulator used (i.e., porcelain, polymer, toughened glass). Periodic coating and/or cleaning of the high-voltage insulators is also included as part of the program (with the frequency determined by site OE). The first inspections for SLR are to be completed prior to the SPEO.

Reduced insulation resistance can be caused by the presence of insulator surface contamination or peeling of silicone rubber sleeves for polymer insulators, or degradation of glazing on porcelain insulators. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance. Corona cameras may also be employed to detect early signs of corona emissions.

The acceptance criteria for the high-voltage insulators are that the surfaces are free from unacceptable accumulation of foreign material, such as dust buildup as well as other contaminants. Metallic parts are free from significant loss of materials due to pitting, fatigue, crevice, and general corrosion. Acceptance criteria will be based on temperature rise above a reference temperature for the application when thermography is used. The reference temperature will be ambient temperature, or a baseline temperature based on data from the same type of high-voltage insulator being inspected.

NUREG-2191 Consistency

The High-Voltage Insulators AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.E7, “High-Voltage Insulators.”

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

The July 2013 Diablo Canyon 500kV flashover event involving high-voltage insulator(s) was reviewed. The flashover event was caused by the accumulation of contaminants (salt spray conditions by the ocean) and lack of rain for 4 weeks (rain naturally washes off accumulated salt). Also, the insulator was of the polymer type that was intended to be more resilient to accumulated contamination.

Two lessons were realized from this event; flashovers do occur from accumulated contamination in areas prone to contamination (sea spray or heavy air pollution contaminants) and polymer insulators are not immune to flashovers due to accumulated contaminants.

In addition, Columbia Generating Station experienced two flashover events in its transformer yard (in 1989 and 1990) when the cooling tower plume slumped over the Reactor Building and allowed the cloud to envelop the transformer yard for a period of time (with no wind or breeze). This moisture, combined with surface contamination (dust/dirt) allowed tracking to occur on surfaces of the porcelain, 500 kV high-voltage insulators (associated with a 115 kV transformer), and flashover conditions ensued.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR which covers the last 10 years of operations and the relevant OE items are as follows.

- In February 2013, hot spots were reported on insulators on a tower in the Thalmann Yard and on a tower in the High Voltage Switchyard. The insulators were cleaned.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The High-Voltage Insulators 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 periodically evaluated.

Conclusion

The High-Voltage Insulators 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.2.4 Plant Specific Aging Management Programs

B.2.4.1 RHR Heat Exchanger Augmented Inspection

Program Description

The RHR Heat Exchanger Augmented Inspection AMP is an existing AMP that inspects, tests, and cleans passive components of the RHR heat exchangers to mitigate flow blockage, prevent reduction of heat transfer and loss of material. The objective of the program is to assure that no unacceptable degradation is occurring. The RHR Heat Exchanger Augmented Inspection and Testing AMP is a condition monitoring program that manages aging of the RHR heat exchangers.

There are two RHR heat exchangers per unit. The RHR Heat Exchanger Augmented Inspection and Testing AMP applies cleaning, visual inspection and eddy current testing in accordance with plant procedures. The program partially satisfies the requirements of Nuclear Regulatory Commission GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment” and incorporates the guidance of Department of Energy (DOE) report, SAND 93-7070.UC-523, "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers" as supplemented by reviews of current industry experience and practice, as the basis for this program.

The RHR Heat Exchanger Augmented Inspection and Testing AMP requires that heat exchanger tubes and channel interior be cleaned on an 8-year frequency. This cleaning of the heat exchanger tubes, and channel head mitigates flow blockage and prevents reduction of heat transfer.

The RHR Heat Exchanger Augmented Inspection and Testing AMP provides for visual inspections of channel side (including partition plate and tube sheet) and tube interior. This activity detects loss of material and flow blockage. The shell side of the tube sheets, shell internals, and impingement plates are visually inspected on an 8-year frequency, where accessible. Although, the visual inspection frequency may be changed based on the trend and engineering evaluation. The inspection focuses on tube interfaces, tie rods or fasteners, and accessible welds. This activity detects loss of material, and flow blockage (fouling).

Eddy current testing is performed at least once (for each RHR heat exchanger) during each 8-year inspection interval and whenever leaks are suspected. Testing is performed by qualified personnel and include accessible portions of the straight tube sections and U-bends of the test sample. This activity detects loss of material. Eddy current examination of at least ten percent of the non-plugged tubes in each RHR heat exchanger tube bundle.

Tube and tube sheet leak testing or inspection is performed whenever leaks are suspected. This activity detects leaks due to loss of material. Inspection and testing results are maintained in plant records and engineering personnel track and trend results in accordance with plant procedures.

Any unacceptable indication of loss of material is evaluated by engineering. When appropriate, engineering evaluations are based upon the design code of record. If warranted, additional inspections are performed. Any significant degradation of components inspected by the RHR Heat Exchanger Augmented Inspection and Testing AMP is noted and corrective actions are implemented in accordance with the existing CAP.

NUREG-2191 Consistency

The RHR Heat Exchanger Augmented Inspection AMP is plant specific and does not have a NUREG-2191 generic 10-element evaluation for comparison, and instead addresses the 10 elements as they are identified in Appendix A Section A.1.2.3 of NUREG-2192, without exception.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. Examples of this are as follows:

- In March 2010 at a PWR, an inspection of a RHR heat exchanger identified some tube wear resulting in ten tubes being plugged; no tubes exhibited thru-wall leakage. Eddy current testing performed on the RHR heat exchanger identified vibration-induced fretting on multiple tubes with most wear occurring at the U-bend section. No tubes were found to be leaking in any of the RHR heat exchanger.

No HNP condition report was identified for a similar condition of tube wear resulting from flow-induced vibrations. ECT is performed periodically (at least once per an 8-year interval) and opted to be used whenever leaks are suspected. ECT is performed on at least 10% of the non-plugged tubes in each RHR heat exchanger tube bundle.

- In March 2015 at a BWR, an inspection of a RHR heat exchanger identified excessive amount of Asiatic clam shell halves on the inlet side of the tube-sheet which could potentially result in fouling of the heat exchanger. The RHR heat exchanger had approximately 305 tubes considered fully blocked by visual observation. The consequence was that this debris accumulation in the RHR heat exchanger could reduce the heat transfer capability of the heat exchanger, resulting in reduced cooling margin.

Visual inspection of the channel side (including partition plate and tube sheet) and tube interior is performed at HNP in accordance with "Heat Exchanger Inspection, Testing and Condition Assessment" procedure to identify such conditions. This activity detects loss of material and flow blockage. Cleaning of the RHR heat exchangers is performed in accordance with "Cleaning of Heat Exchangers" procedure and preventive actions for biofouling are performed as described in the Open-Cycle Cooling Water System AMP.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In June 2018, RHRSW was leaking into the U1 RHR system which indicated a tube leak on Unit 1 RHR heat exchanger (HX) B. Unit 1 RHR system was experiencing slow but steady pressurization and all other possible source of RHRSW in leakage into RHR were ruled out. A work order was completed to plug the leaking tube.

- In November 2019, eight tubes were eddy current tested after being plugged due to an adjacent tube leakage that had the potential for damaging the eight adjacent tubes. After stabilizing the damaged tube, the condition of adjacent tubes was verified using eddy current test before they were returned to service.

- In February 2020, the results of a visual inspection performed on 1B RHR HX identified an area of approximately 8 inches that showed evidence of by-pass flow. By-pass flow is where the inlet water is able to flow under the divider plate, by-passing the tube bundle reducing the flow through the heat exchanger. In addition, protective coating on the inside of the inlet and outlet channels was identified to be chipping in various locations. These indications were repaired and the head was replaced.

- In February 2020, ECT of the 1B RHR HX discovered two tubes with non-identifiable indications which were recommended to be plugged by the NDE vendor. ECT did not indicate these flaws were through walls leaks; however, in 2018 these indications were not there. Based on this 2020 ECT, the indications have changed drastically in the absolute range indicating large tube wall degradation that has appear in a short amount of time. Thus, the tubes were plugged to eliminate potential mid-cycle tube leaks or breaks of identified flawed tubes with growth rates that could not be quantified by a vendor.

- In February 2023, the 2B RHR HX divider plate and all sealing surfaces were identified as having some degree of degradation. The degradation was not as severe as that found on the 1B RHR HX. The degradation appeared to be years of corrosion that had caused loss of material at the edges and corners of the sealing surfaces. A determination was made that it was not imperative to perform the repairs during that Unit 2 Spring 2023 outage and the 2B RHR HX would be operable until it could be repaired during a future outage.

These condition reports demonstrate the adequacy of the CAP to provide reasonable assurance that the applicable aging effects will be managed such that the RHR heat exchangers will maintain their intended function.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The RHR Heat Exchanger Augmented Inspection 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 periodically evaluated.

Conclusion

The RHR Heat Exchanger Augmented Inspection 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.2.4.2 Torus Submerged Components Inspection

Program Description

The Torus Submerged Components Inspection Program is an existing condition monitoring program that monitors SSCs submerged within the suppression pool and in the vapor space directly above the suppression pool for loss of material and cracking. The vapor space is the location at or just above the suppression pool water line where it is more susceptible to corrosion due to the effects of alternate wetting and drying (splash zone). The objective of the program is to assure that no unacceptable degradation is occurring. This inspection is intended to validate the adequacy of suppression pool chemistry controls to manage aging effects for a variety of uncoated structures and components that are exposed to the suppression pool environment.

Torus submerged components inspections are conducted on accessible components submerged in suppression pool water or directly above the suppression pool in the vapor space, including the emergency core cooling system (ECCS) pump suction strainers and the RCIC pump suction strainer. The submerged portion of the SRV and vacuum relief piping is also included, as is the carbon steel, non-class 1 piping. Baseline examinations for this program were performed prior to entering the PEO to examine a sample set of the uncoated components in the torus within the scope of LR. This sample was biased towards the areas most likely to exhibit corrosion related degradation such as weld heat affected zones and crevices. The results of the initial inspections were used to determine ongoing inspection scope and frequency. These inspections will continue throughout the SPEO.

The Torus Submerged Components Inspection Program is a condition monitoring activity that utilizes visual inspections to identify unacceptable corrosion on components submerged within the suppression pool. As such, there are no preventive or mitigative attributes associated with this program. Detailed visual inspections for evidence of MIC, pitting or crevice corrosion, or similar mechanisms are performed on the in-scope components. Visual inspections are conducted using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210, or other suitable method as dictated by the component configuration.

Results of Torus Submerged Components Inspection AMP inspections are documented in accordance with HNP procedural requirements. The CAP is utilized to monitor and trend deficiencies and to implement timely corrective actions. Any unacceptable indication of loss of material or cracking is evaluated by engineering. When appropriate, engineering evaluations are based upon the design code of record. If warranted based upon the results of the initial inspections, inspections of additional locations within the torus are performed. Corrective actions are implemented in accordance with the CAP.

NUREG-2191 Consistency

The Torus Submerged Components Inspection AMP is plant specific and does not have a NUREG-2191 generic 10-element evaluation for comparison, and instead addresses the 10 elements as they are identified in Appendix A Section A.1.2.3 of NUREG-2192, without exception.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

HNP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. Relevant Industry OE is as follows:

- An event occurring in March 2010 describes damage to the HPCI and RCIC torus suction strainers. Large perforations on the strainers were identified by divers. The perforations were large enough to pass debris greater in size than what the strainers were designed for leading to concerns about flow blockage or debris in the reactor vessel. It was determined that the cause of these perforations was improper installation approximately 28 years prior. It was suggested that the industry adopt an inspection PM to validate acceptable equipment conditions. Evaluation of this OE verified that the Torus Submerged Components Inspection AMP, which utilizes periodic inspections, would allow for early detection of unacceptable material conditions in the equipment submerged in the torus or directly above in the vapor space.

- An event occurring in January 2017 describes deficiencies that were identified during the inspection of the RHR suction strainers. The strainers showed signs of loss of material and linear cracking. It was determined that the cause of the deficiencies was cyclic stress caused by hydrodynamic loading in combination with high mean stresses from fabrication. Evaluation of this OE verifies that the Torus Submerged Components Inspection AMP utilizes periodic inspection that would allow for early detection of adverse conditions.

- An event occurring in November 2019 describes two through wall perforations in the torus T-quencher. It was determined that the damages were caused by prolonged SRV leakage which led to localized cavitation from steam condensation in the down-comer piping. The torus was drained and the damaged portions of the T-quenchers were replaced, resulting in an eight-day extension to the refueling outage. Evaluation of this OE verifies that the Torus Submerged Components Inspection AMP utilizes periodic inspection that would allow for early detection of adverse conditions.

- An event occurring in March 2021 describes inspections of the main steam relief valve T-quenchers where a through wall perforation was discovered at the welded connection of the sparger and rams head. The cause was prolonged SRV leakage which led to localized cavitation from steam condensation in the down-comer piping. Evaluation of this OE verifies that the Torus Submerged Components Inspection AMP utilizes periodic inspection that would allow for early detection of adverse conditions.

Plant Specific Operating Experience

A recent HNP OE search was performed for SLR covering the last 10 years of operation and the relevant OE items are as follows:

- In February 2014, while performing inspections of the RCIC suction strainers, it was noted that all of the strainer’s carbon steel bolting had material loss and at least one of the bolts had minimal thread engagement. A work order was issued and the nuts and bolting were replaced.

- In February 2015, divers identified a pit in the Unit 2 torus. The pitting measured 0.0603 inches. A work order was issued and the area was cleaned and recoated to prevent further degradation.

- In February 2022, a spot of corrosion was found on the Unit 1 torus. The corrosion spot had an actual metal thickness loss of 0.0643 inches which exceeded the acceptance criteria indicated in the Torus Submerged Components Inspection Program procedures.

A work order was issued and the area was cleaned and recoated to prevent further corrosion.

- In February 2022, while performing torus T-quencher bolt inspections, divers identified a combined total of 19 loose bolts from three T-quenchers in the Unit 1 torus. Minor corrosion was also noted on the bolting. The work order which was written to perform the inspections, was modified and divers tightened all loose bolting.

- In February 2024, while performing torus T-quencher bolt inspections, divers identified a combined total of 53 loose bolts from nine T-quenchers in the Unit 1 torus. Minor corrosion was also noted on the bolting. Following the inspections, divers tightened and re-staked all loose bolting.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Torus Submerged Components Inspection 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 periodically evaluated.

Conclusion

The Torus Submerged Components Inspection 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.

Appendix C

Response To BWRVIP License Renewal Applicant Action Items

Of the BWRVIP reports credited within HNP's license renewal 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 Standby Liquid Control System/Core Plate dP
- BWRVIP-38; BWR Shroud Support Inspection and Flaw Evaluation Guidelines
- BWRVIP-41-R4-A; BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines
- 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 (BWRVIP-48-R2 is 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-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines
- 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
- BWRVIP-315-A, BWR Vessel and Internals Project, Reactor Internals Aging Management Evaluation for Extended Operations

License renewal applicant action items identified in the corresponding SERs for each of the above BWRVIP reports are addressed in the following tables. BWRVIP reports without SERs for license renewal do not have action items and are therefore not included in the tables.

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.

BWRVIP-315-A does not have applicant action items but does contain "Conditions" and "Limitations" that are addressed in Table C-3. The BWR Vessel Internals (B.2.3.7) AMP contains enhancements related to incorporation of BWRVIP-315-A.

Table C-1 Common Action Items from BWRVIP-18-R2-A, -25-R1-A, -26-A, -27-A, -38, -41-R4-A, -47-A, -48-A, -49-A, -74-A, -76-R1-A	
Action Item Description	**HNP 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 aging management programs within these BWRVIP reports described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the components or other information presented in the reports, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWRVIP reports applicable to HNP have been reviewed and HNP AMPs have been verified to be bounded by the reports. Additionally, HNP is compliant with programs described as necessary in the BWRVIP reports to manage the effects of aging during the subsequent period of extended operation. These implementation actions 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. Implementation actions are administratively controlled in accordance with the requirements of 10 CFR 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 FSAR supplement is included in SLRA Appendix A. The FSAR supplement includes a summary description of the programs and activities specified as necessary for managing the effects of aging and the evaluation of TLAAs per the BWRVIP reports.

Table C-1 Common Action Items from BWRVIP-18-R2-A, -25-R1-A, -26-A, -27-A, -38, -41-R4-A, -47-A, -48-A, -49-A, -74-A, -76-R1-A	
Action Item Description	**HNP 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 aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the inspection strategy described in the reports does not conflict with or result in any changes to their technical specifications. If technical specification changes or additions do result, then the applicant must ensure that those changes are included in its application for license renewal.	There are no changes to technical specifications that are required to meet the requirements of the BWRVIP reports during the subsequent period of extended operation. Reference SLRA Appendix D.

Table C-2	
BWRVIP-18-R2-A, Core Spray Internals Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP Response**
BWRVIP-18-R2-A (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 these core spray components as discussed in SLRA Section 4.3.3 and Section 4.3.4.
BWRVIP-25-R1-A, Core Plate Inspection and Flaw Evaluation Guidelines	
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 to prevent lateral motion of the core plate is a potential TLAA issue only for those plants that do not have core plate wedges installed. HNP has installed core plate wedges in both Units 1 and 2, therefore, there is no associated TLAA.
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.	HNP has installed core plate wedges in both Units 1 and 2, therefore inspections of the rim hold-down bolts are not required.

Table C-2	
BWRVIP-26-A, BWR Top Guide Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP 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 is projected to exceed the fluence threshold prior to the SPEO. Fluence for reactor internals is evaluated as a TLAA in SLRA Section 4.2.1.2. During the SPEO, the aging of the top guide will be managed by inspections conducted as part of the BWR Vessel Internals (B.2.3.7) AMP per guidance provided in BWRVIP-26-A and BWRVIP-183-A. The program requires that at least 10 percent of the grid beam cells containing control rod blades will be inspected every 12 years. HNP 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. Inspections will continue to be performed as described above during the SPEO.
BWRVIP-27-A, BWR Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines	
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 the SLC system/core plate dP penetration. A TLAA is used to manage cumulative fatigue damage for the RPV and RVI components as discussed in SLRA Section 4.3.3 and Section 4.3.4. The SLC system/core plate dP penetration is bounded by other locations.

Table C-2	
BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP 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. TLAAs are used to manage cumulative fatigue damage for BWR lower plenum components as discussed in SLRA Sections 4.3.2, 4.3.3 and 4.3.4.
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
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) piping is included in the scope of subsequent license renewal. The VFLD piping is fabricated from stainless steel. Loss of material and cracking for stainless steel components is managed by the BWR Stress Corrosion AMP (B.2.3.5), One-Time Inspection AMP (B.2.3.20), and the Water Chemistry AMP (B.2.3.2).
BWRVIP-74-A (5) LR applicants shall describe how each plant-specific aging management program addresses the following elements: (1) scope of program, (2) preventive 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 aging management programs credited for managing the reactor pressure vessel are given 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	**HNP 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" 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. Aging management programs 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-R1-A for the SPEO.

Table C-2	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP 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.2.2.2) 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 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.

Table C-2

BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines

Action Item Description	HNP 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 SPEO, the circumferential welds for each unit will satisfy the limiting conditional failure frequency for circumferential welds in the staff's July 28, 1998, FSER. Relief from the inservice inspection of the circumferential welds during the second period of extended operation is discussed in SLRA Section 4.2.5.
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.	Neutron fluence calculations for HNP are performed using the BWRVIP-developed Radiation Analysis Modeling Application (RAMA) methodology, which was approved by the NRC when reviewing the topical report BWRVIP-114-A, "RAMA Fluence Methodology Theory Manual" (ML100320689). RAMA was used to project neutron fluence during the SPEO, as discussed in SLRA Section 4.2.1.

Table C-2	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP 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 reevaluated for the 60-year service period corresponding to the LR term.	The HNP Unit 1 RPV closure head dollar plate weld indication # 16 meets the fracture mechanics requirements of ASME XI IWB-3612 and has been analytically evaluated to be acceptable through the end of the SPEO, as discussed in SLRA Section 4.3.9.
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
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-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 BWR Vessel Internals program includes reference to BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-R1-A for evaluation of crack growth. The current guidance references BWRVIP-14-A and BWRVIP-99-A for crack growth rates and BWRVIP-100-R1-A for fracture toughness values. The implementing procedures for the BWR Vessel Internals AMP include the requirement to incorporate new guidance within new or revised BWRVIP reports. This ensures that any emerging inspection guidelines developed by the BWRVIP for these core shroud welds will be incorporated into the program.

Table C-2	
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP Response**
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 BWR Vessel Internals AMP (B.2.3.7) describes the HNP Unit 1 tie rod repair cracking in the industry operating experience section and describes the inspection requirements for the core shroud tie rod repairs. HNP discovered Unit 1 cracking on the tie rod repair assembly and implemented a new tie rod repair design on Unit 1 and 2 to address the cracking. No subsequent cracking has been identified in subsequent inspections. HNP incorporates the BWRVIP inspection guidelines and recent OE associated with core shrouds.

Table C-2	
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP 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 aging management programs or time-limited aging analyses that will be used to manage these aging effects during the period of extended operation. Refer to License Renewal Applicant Action Item 7) for additional guidance on identifying the AERMs for core shroud components or core shroud repair assembly components that are made from materials other than stainless steel (including CASS) or nickel alloy.	The Unit 1 core shroud (including welds) is made from austenitic stainless-steel Type 304. The Unit 2 core shroud is Type 304 and Type 304L. The core shroud repair assembly components (tie rod assemblies) are made from nickel alloy X-750 and XM-19. Cumulative fatigue damage for the core shroud has been identified as a TLAA as discussed in SLRA Section 4.3.3 and 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	**HNP 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. Core shroud repair assembly components are fabricated with nickel alloy. Therefore, there are no core shroud components made from materials other than stainless steel or nickel alloy that need to be 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, BWRVIP-99-A, and BWRVIP-100-R1-A. The aging management program 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-R1-A for evaluation of crack growth.

Table C-2	
BWRVIP-139-R1-A, BWR Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP 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.	a. HNP has performed a review of the CLB and design basis to determine whether there are any additional aging effects/mechanisms that might be applicable to the designs of the steam dryer assemblies, in addition to those that are mentioned as being applicable aging effects/mechanisms requiring management in BWRVIP-139-R1-A, Appendix B. The HNP steam dryers are original GEH equipment. The only aging effects applicable for license renewal are cracking and loss of material. These effects will be managed by the BWR Reactor Vessel Internals AMP (B.2.3.7). There are no additional aging effects or mechanisms applicable to the GEH OEM designs of the HNP steam dryer assemblies.

Table C-2	
BWRVIP-139-R1-A, BWR Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP Response**
b. For those BWR license renewal applicants that identify additional 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)	b. HNP has performed a review of the CLB and design basis to determine whether there are any additional aging effects/mechanisms that might be applicable to the designs of the steam dryer assemblies, in addition to those that are mentioned as being applicable aging effects/mechanisms requiring management in BWRVIP-139-R1-A, Appendix B. There are no additional aging effects requiring management applicable to the GEH design of the HNP steam dryer assemblies.
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 HNP FSAR supplement summary description for the BWR Vessel Internals AMP in SLRA Section A.2.2.7 follows the NUREG-2191 Table XI-01, FSAR Supplement Summaries for GALL-SLR Report higher level detail content and therefore does not specifically describe how the BWRVIP-139-R1-A report and Appendix B of the report will be used to manage aging in the HNP steam dryer assembly components during the SPEO. SLRA Section B.2.3.7 states that steam dryer inspections and evaluations are performed in accordance with BWRVIP-139, Revision 1-A which provides guidelines for inspection and evaluation for the steam dryer components.

Table C-2	
BWRVIP-139-R1-A, BWR Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**HNP Response**
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 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.	HNP does not have a steam dryer analysis in the CLB that conforms to the definition of a TLAA per 10 CFR 54.3.

Table C-3	
BWRVIP-315-A, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**HNP Response**
BWRVIP-315-A (Condition 1) Applicants for renewed operating licenses extending beyond 60 years applying Code Case N-889 to calculate IASCC crack growth rate must comply with the conditions in the latest edition of Regulatory Guide 1.147 incorporated by reference in 10 CFR 50.55a.	Code Case N-889 is not applied in the Reactor Vessel Internals Program. If Code Case N-889 is used, the calculations will comply with the conditions in the latest edition of RG 1.147.
BWRVIP-315-A (Condition 2) Applicants for renewed operating licenses extending beyond 60 years must describe whether the core plate hold-down bolt analysis per BWRVIP-25, Appendix I is a TLAA. If so, the applicant must include the analysis as a TLAA in the licensing application.	Preload of the rim hold-down bolts to prevent lateral motion of the core plate is a potential TLAA issue only for those plants that do not have core plate wedges installed. HNP has installed core plate wedges in both Units 1 and 2, therefore, there is no associated TLAA.
BWRVIP-315-A (Condition 3) Applicants for renewed operating licenses extending beyond 60 years must describe and justify plant-specific re-inspection plans for the lower plenum in the application.	The BWRVIP-47-A Section 3.2.2 baseline examinations of the CRGT-1, CRGT-2, CRGT-3 and Fuel Support/Guide Tube – Anti-Rotation Pin locations were complete in 2002 for HNP 1, and in 2001 for HNP 2, with no relevant indications observed. HNP is committed to implementing any reinspection recommendations provided by BWRVIP. While the potential for reinspection recommendations continues to be evaluated, HNP will perform Fuel Support/Guide Tube – Anti-Rotation Pin examinations at available locations during blade shuffles each refueling outage which will provide indications of any gross failures. Consistent with BWRVIP-47-A Section 3.2.5, during maintenance activities outside of normal outage activities a visual examination is performed to the extent practical with results reported to BWRVIP and subsequently forwarded to the NRC.

Table C-3	
BWRVIP-315-A, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**HNP Response**
BWRVIP-315-A (Condition 4) Applicants for renewed operating licenses extending beyond 60 years must justify applicability for non-RAMA-based, plant-specific fluence evaluations. Alternatively, the BWRVIP may address the generic qualification to evaluate RVI component fluence for each fluence methodology in use at operating BWRs.	TransWare Radiation Analysis Modeling Application (RAMA) methodology was used to develop fluence projections for reactor pressure vessel (RPV) and internal (RVI) components that are used in evaluating TLAAs in SLRA Sections 4.2.2 through 4.2.8.
BWRVIP-315-A (Condition 5) Applicants for renewed operating licenses extending beyond 60 years must describe in the application how they meet the seven BWRVIP-defined limitations in BWRVIP-315-A, Section 4.5.1:	
<u>Limitation 1 – Core Plate Hold-down Bolting Evaluation:</u> Core plate hold-down bolting is subject to a plant-specific evaluation or to augmented inspections if the criteria for use of the generic evaluation documented in BWRVIP-25, Rev. 1 cannot be met. BWRVIP-25, Rev. 1 provides guidance for performing such a plant-specific evaluation. The relevant limitation applicable to extended operation is core plate hold-down bolt fluence. See Section 4.3.2 for additional discussion. This limitation is already appropriately identified and described within BWRVIP-25, Rev. 1 (See BWRVIP-25, Rev. 1, Appendix I). No revision to BWRVIP-25, Rev. 1 is needed to address extended operations.	HNP core plates were modified to install wedge assemblies that replace the lateral support function of the core plate hold-down bolts. Therefore, consistent with the conclusions presented in BWRVIP-25, Rev. 1-A, loss of preload of the rim hold-down bolts is not an aging effect requiring management and evaluation of core plate hold-down bolt preload is not required.

Table C-3	
BWRVIP-315-A, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**HNP Response**
<u>Limitation 2 – CRGT Aging Management:</u> BWRVIP-47-A provides for a set of baseline examinations of CRGTs. Section 3.2.2 of BWRVIP-47-A states: *Currently no additional inspections are recommended beyond the baseline inspections described in Section 3.2.2, and scope expansion and follow-on inspections deemed necessary in the event flaws are found as given in Section 3.2.3. Baseline inspection results will be reviewed by the BWRVIP and, if deemed necessary, reinspection recommendations will be developed at a later date and provided to the NRC.* Since the BWRVIP has not yet completed an evaluation to assess reinspection needs in a manner that considers extended operations, until such time as a new version of BWRVIP-47 is developed, owners submitting an application for operation beyond 60 years (e.g., an SLRA in the U.S.) should either commit to implementing a future version of BWRVIP-47 that addresses extended operations or propose a set of plant-specific activities to manage age-related degradation of CRGTs. Given that changes to BWRVIP-47 to address extended operations will be dependent on the outcome of the evaluation described above, proposed changes to address this issue cannot be proposed at this time.	BWRVIP-47-A recommends performing baseline inspections of the guide tube to alignment lug weld (CRGT-1) and the guide tube circumferential welds (CRGT-2 and CRGT-3). These baseline inspections were performed at HNP during the Unit 1 Spring 2002 and Unit 2 Spring 2001 Refueling Outages. The industry baseline inspection results are under evaluation and future inspection recommendations are pending. Any new or revised inspection recommendations in BWRVIP-47 are required to be implemented in accordance with BWRVIP-94-R4: BWR Vessel and Internals Project, Program Implementation Guide and NEI 03-08, Guideline for the Management of Material Issues. Future revisions of BWRVIP-47 that address HNP extended operations will be implemented into plant procedures or processes.

Table C-3	
BWRVIP-315-A, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**HNP Response**
Limitation 3 - CASS Embrittlement: Jet pump and LPCI coupling CASS components subjected to fluence exceeding $6x10^{20}$ n/cm^2 (E > 1.0 MeV) must be evaluated on a plant-specific basis or be included in a plant-specific aging management program. This limitation is based on the fluence criterion contained in BWRVIP-234-A. BWRVIP I&E guidelines affected include BWRVIP-41 and BWRVIP-42. See Sections 4.3.8 and 4.3.10 for additional discussion. Appropriate changes to BWRVIP-41 to identify this limitation are included in Appendix B, Section B.1. Appropriate changes to BWRVIP-42 to identify and describe this limitation are included in Appendix B, Section B.2.	The HNP reactor vessel internals do not include Low Pressure Coolant Injection (LPCI) couplings and therefore this component is not applicable for evaluation. Vessel internals components subject to screening for end of life fluence are evaluated in Section 4.2.8. The only jet pump components expected to exceed the screening threshold are the Unit 2 jet pump restrainer brackets, and as such, 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). For periodic jet pump assembly inspections, the HNP BWR Vessel Internals AMP (B.2.3.7) utilizes the recommendations provided in BWRVIP-41-R4-A "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines." This is consistent with the BWRVIP-315-A Limitation 4 associated with BWRVIP-41-R4-A in this table.

Table C-3	
BWRVIP-315-A, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**HNP Response**
Limitation 4 – Jet Pump Large Diameter Weld Scope Expansion Exemption: A scope expansion exemption is provided within BWRVIP-41, Rev. 4-A for large diameter jet pump diffuser, adapter, and lower ring welds (DF-1, DF-2, DF-3, AD-1, AD-2, and AD-3a,b) inspected by UT. As currently included in BWRVIP-41, Rev. 4-A, the exemption is based on an assumption of a 60-year service life. As discussed in Section 4.3.8, this exemption will be revised to be interval-based (24-year intervals allowed) rather than based on a 60-year service life. Until such time as BWRVIP-41 is revised, use of the scope expansion exemption allowance should be limited to plants not intending to operate beyond 60 years. Appropriate changes to BWRVIP-41 that are planned to eliminate this limitation are described in Appendix B, Section B.1.3.	The BWRVIP-41, Revision 4-A jet pump large diameter weld scope expansion has not been required for HNP. To ensure the scope expansion exemption for large diameter jet pump diffuser, adapter, and lower ring welds is not used in the SPEO, the Reactor Vessel Internals program will be enhanced to indicate the scope expansion exemption is limited to 60 years of operation and not intended for use beyond 60 years, the BWRVIP-41, Revision 4-A assumption, until such time as BWRVIP-41 is revised to eliminate the limitation.
Limitation 5 – Jet Pump Hold-down Beam IASCC: Jet pump hold-down beams subject to neutron fluence exceeding $5x10^{20}$ n/cm^2 (E > 1.0 MeV) in the BB-2 region require plant-specific evaluation to address IASCC concerns. This limitation is applicable to BWRVIP-41. Appropriate changes to BWRVIP-41 to identify and describe this limitation are included in Appendix B, Section B.1.	All HNP Unit 1 and Unit 2 jet pump hold-down beams have been replaced with group 2 hold-down beams with the exception of one group 3 type ratcheting hold-down beam on Unit 1. HNP plant specific fluence projections were performed for the jet pump hold-down beams. The projected fluence at the end of the SPEO for the hold down beams is below $5x10^{20}$ n/cm^2 (E > 1.0 MeV). No further actions are required.

Table C-3 BWRVIP-315-A, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**HNP Response**
<u>Limitation 6 – Jet Pump Hold-down Beam Stress Relaxation:</u> Jet pump hold-down beams having peak neutron fluence exceeding 7.0×10^{20} n/cm^2 (E > 1.0 MeV) for Group 2 beams or 5.8×10^{20} n/cm^2 (E > 1.0 MeV) for Group 3 beams require plant-specific disposition. This limitation ensures that sufficient preload to prevent jet pump disassembly and potential damage is maintained. Plant-specific disposition may include refined analysis to demonstrate adequate preload remains for operation at higher neutron fluences. Alternatively, plants may replace or re-tension beams with neutron fluence exceeding the threshold value. This limitation is applicable to BWRVIP-41. Appropriate changes to BWRVIP-41 to identify and describe this limitation are included in Appendix B, Section B.1.	All HNP Unit 1 and Unit 2 jet pump hold-down beams have been replaced with group 2 hold-down beams with the exception of one group 3 type ratcheting hold-down beam on Unit 1. HNP plant specific fluence projections were performed for the jet pump hold-down beams. The projected fluence at the end of the SPEO for the hold down beams is below 5×10^{20} n/cm^2 (E > 1.0 MeV). No further actions are required.
<u>Limitation 7 – Core Shroud Repair Hardware Aging Management:</u> Core shroud tie rod repairs require plant-specific evaluation. Inspections should, as a minimum, meet the requirements listed in BWRVIP-76, Rev. 1-A. However, additional evaluations must be performed to address aging management associated with operation beyond the original repair hardware service life specified by the designer. See Section 4.3.13 for additional discussion. Also see Appendix B, Section B.5.	HNP installed a core shroud tie-rod repair during the 1994 refueling outage on Unit 1 and the 1995 refueling outage on Unit 2. Subsequent tie-rod inspections meet the requirements of BWRVIP-76-R1-A and vendor repair design requirements. HNP inspects all 4 tie rods and anchorages in accordance with BWRVIP-76-R1-A and vendor repair design requirements. HNP will continue inspecting the tie-rod hardware and anchorage per BWRVIP-76-R1-A and vendor repair design requirements throughout the SPEO. The projected fluence for the core shroud repair is below the threshold for stress relaxation at 1.03×10^{20} n/cm^2 (E > 1.0 MeV) for Unit 1 and 7.38×10^{19} n/cm^2 (E > 1.0 MeV) for Unit 2 as shown in SLRA Section 4.2.1.2. No further actions are required.

Appendix D

Technical Specification Changes

10 CFR 54.22 requires that an application for license renewal include any Technical Specification changes or additions necessary to manage the effects of aging during the SPEO.

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.